Dave Olsen

DOE/ID/10412-6

GEOTHERMAL AND HEAVY-OIL RESOURCES IN TEXAS

TOPICAL REPORT

By Steven J. Seni and Timothy G. Walter

January 1994

DISCLAIMER

Work Performed Under Contract DE-FC07-85ID10412
For
U. S. Department of Energy
Office of Industrial Technologies
Washington, D.C.

By
Bureau of Economic Geology
The University of Texas at Austin
Austin, Texas 78713-7508

Contents

Figures

Tables

Contents

Abstract

In a five-county area of South Texas, geopressured-geothermal reservoirs in the Paleocene–Eocene Wilcox Group lie below medium- to heavy-oil reservoirs in the Eocene Jackson Group. This fortuitous association suggests the use of geothermal fluids for thermally enhanced oil recovery (TEOR). Geothermal fairways are formed where thick deltaic sandstones are compartmentalized by growth faults. Wilcox geothermal reservoirs in South Texas are present at depths of 11,000 to 15,000 ft (3,350 to 4,570 m) in laterally continuous sandstones 100 to 200 ft (30 to 60 m) thick. Permeability is generally low (typically 1 md), porosity ranges from 12 to 24 percent, and temperature exceeds 250°F (121°C).

Reservoirs containing medium (20° to 25° API gravity) to heavy (10° to 20° API gravity) oil are concentrated along the Texas Coastal Plain in the Jackson-Yegua Barrier/Strandplain (Mirando Trend), Cap Rock, and Piercement Salt Dome plays and in the East Texas Basin in Woodbine Fluvial/Deltaic/Strandplain and Paluxy Fault Line plays. The Jackson-Yegua Barrier/Strandplain (Mirando Trend) is the most favorable play for TEOR of medium to heavy oil because of the abundance of candidate reservoirs, relative simplicity of reservoir architecture, and shallow depth of burial. Updip pinch-out of shallow barrier bar/strandplain sandstones largely controls the distribution of medium- to heavy-oil reservoirs in the Jackson Group. Subtle structure, small faults, and sandstone-body pinch-outs form lateral barriers of the reservoirs. Structural, depositional, and diagenetic variations cause reservoir compartmentalization. The medium- to heavy-oil reservoirs are typically porous (25 to 35 percent) and permeable (100 to 1,000 md), slightly clayey, fine- to medium-grained sand and sandstones. Calcite-cemented zones of low porosity (approximately 5 percent) and permeability (approximately 0.01 md) compartmentalize the reservoirs.

Injection of hot, moderately fresh to saline brines will improve oil recovery by lowering viscosity and decreasing residual oil saturation. Smectite clay matrix could swell and clog pore throats if injected waters have low salinity. The high temperature of injected fluids will collapse some of the interlayer clays, thus increasing porosity and permeability. Reservoir heterogeneity resulting from facies variation and diagenesis must be considered when siting production and injection wells within the heavy-oil reservoir. The ability of abandoned gas wells to produce sufficient volumes of hot water over the long term will also affect the economics of TEOR.

Keywords: geopressured-geothermal reservoirs, hot-water flood, Jackson Group, Mirando Trend, oil plays, South Texas, thermally enhanced oil recovery, Wilcox Group

Introduction

In Texas, geothermal resources are largely untapped despite their wide distribution. Three regions in the State that contain geothermal resources include the (1) geopressured-geothermal zone along the Texas Gulf Coast, (2) rift-associated hydrothermal area of the Trans-Pecos, and (3) fault-associated hydrothermal area of Central Texas (fig. 1). Geothermal resources could provide an auxiliary source of energy for diverse applications as well as a possible supply of potable water at some localities. Low-temperature hydrothermal resources associated with the Balcones and Mexia-Talco Fault Zones have experienced the most, albeit limited, development in Texas (Woodruff, 1982). Geopressured-geothermal resources along the Texas Gulf Coast have received the most study (for example, Meriwether, 1977; Bebout and Bachman, 1981; Dorfman and Morton, 1985; Negus-de Wys, 1990, 1991; Riggs and others, 1991) because they possess the highest temperatures and have associated natural gas. In the 1970's, early estimates indicated that vast energy resources associated with the geopressured-geothermal fluids might be able to generate electricity and produce natural gas (Jones, 1976; Wallace and others, 1979). Subsequent resource estimates using data gathered from geopressured-geothermal research programs drastically shrank the earlier overly optimistic estimates of the size of the resource base

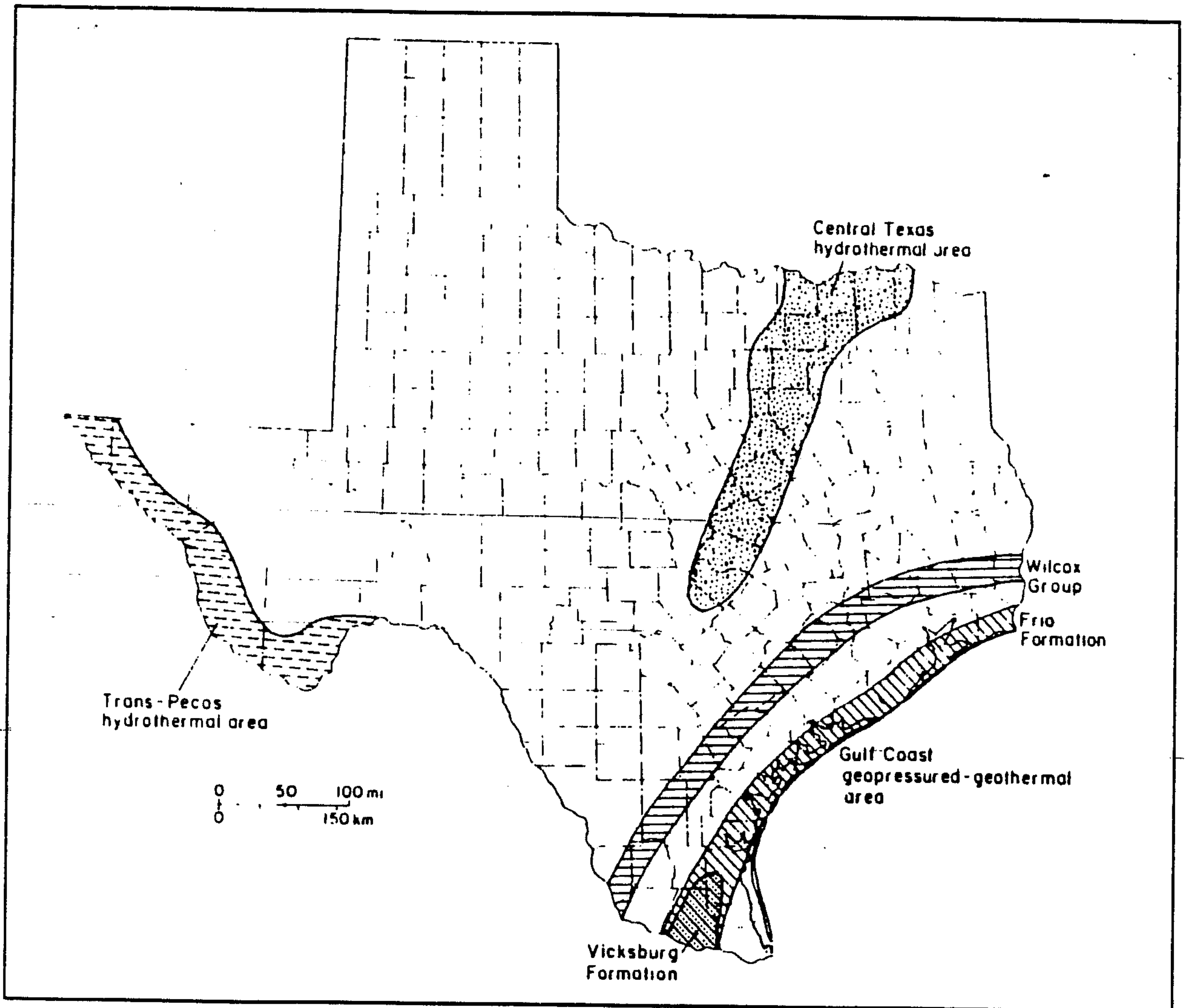


Figure 1. Map outlining areas containing geothermal resources in Texas and geopressured-geothermal corridors along Texas Gulf Coast (Bebout and others, 1978, 1982; Gregory and others, 1980; Woodruff, 1982).

(Gregory and others, 1980). Declines in the price of oil and gas also had a negative impact on the economics of geothermal resource utilization (Wrighton, 1981). Without price or tax incentives, the generation of electricity through production of geopressured-geothermal energy is unlikely to be economical, given the current price (1990–1992) for competitive energy sources such as oil ($20 to $25/bbl) and gas ($1.50 to $2.00/Mcf).

Geothermal waters in Texas range in temperature from less than 100°F to greater than 350°F (<38°C to >177°C) but are not hot enough to directly generate electricity using steam-driven turbines. These geothermal resources may be suitable for binary-cycle conversion, in which the geothermal fluids vaporize a working fluid (freon, isobutane, or isopentane), which would then drive a turbine-generator. The technology for commercial use of moderate-temperature geothermal fluids to generate electricity has been proven in California and has also been successfully tested in a geopressured-geothermal well in Texas.

Generating electricity efficiently from geopressured-geothermal resources requires using all of the multiple components of the resource, such as thermal energy (hot water), chemical energy (dissolved natural gas), and kinetic energy (hydraulic power), each of which is uneconomical to exploit individually. The large initial investment inhibits developing geothermal resources that are a relatively low unit value commodity. In Texas, the commercial success of such a procedure is currently hampered by uncertainties about the size and productivity of individual geothermal reservoirs, low prices for natural gas, flat demand for electricity, higher rate of return from competing energy resources such as oil and gas, high costs of drilling and completing geothermal wells, high costs of customized plant design and fabrication, and high costs of disposal of spent fluids. Geothermal fluid must also be produced cheaply and in large quantities to be economically feasible. The economics are especially sensitive to the flow rate and productive life of individual wells, which are best determined on the basis of long-term flow tests. Many variables can affect well productivity and flow rates, and reservoir performance must be individually determined for each well. However, the direct use of geopressured-geothermal fluids for applications that require varying temperatures is the most likely way the energy will be used in the near term (Lunis and others, 1991).

Direct Use of Geothermal Resources

Direct uses include space heating or other industrial processes that require moderate temperatures, such as agriculture, aquaculture, or thermally enhanced oil recovery (TEOR). First proposed by Negus-de Wys (1989), recovery of heavy oil by injecting geopressured-geothermal fluids for hot-water flooding is one direct-use method with particularly attractive economic incentives (Negus-de Wys and others, 1991). Heavy-oil reservoirs are characterized by poor recovery efficiencies because the oil is highly viscous and resists extraction. Enhanced recovery strategies that apply geothermal energies to reduce viscosity in medium- to heavy-oil reservoirs have the potential to improve recovery efficiency, resource conservation (heat would not be generated by combustion), and environmental protection (no release of greenhouse gases). Because of the difficulty of conserving the heat energy during long-distance transport (Hannah, 1975), geothermal resources must be located close to heavy-oil reservoirs.

In the Gulf Coast region, geothermal and heavy-oil resources are located together in South Texas where a geothermal fairway in the Paleocene–Eocene Wilcox Group lies 2 to 3 mi (3 to 5 km) below a trend of heavy-oil reservoirs in the shallow Eocene Jackson Group. Geothermal fluids produced from the deeply buried Tertiary geopressured-geothermal reservoirs could be injected into shallow oil reservoirs to supply both the heat energy and fluid for enhanced oil recovery by steam or hot-water flooding (fig. 2). Although the incremental gain in production from injecting hot water is substantial compared with that gained from injecting cold water during a typical waterflood, such improvements are less significant than those resulting from injecting steam (Burger and others, 1985). A TEOR process would result in energy savings and resource conservation by maximizing the percentage of oil recovered from the reservoir and by eliminating the standard practice of heating the injection fluids through combustion of hydrocarbons. In situations where steam injection is impractical or uneconomical, injection of geothermally heated water may offer an economically attractive alternative. Although Negus-de Wys and others (1991) suggested that TEOR geopressured-geothermal fluids could be economically viable in South Texas because of the colocation of geothermal resources below heavy-oil reservoirs and because of the size of the heavy-oil and geothermal resources, the geothermal-well productivity and dissolved gas content may have been overestimated.

Objectives

This report characterizes geothermal resources and medium- to heavy-oil reservoirs in Texas, with emphasis on the South Texas area where geothermal and medium- to heavy-oil reservoirs are colocated. Specifically, we consider the feasibility of using geothermal brines to supply heat and fluids for a TEOR program to increase production from medium- to heavy-oil reservoirs. The report is organized in five sections that (1) provide background information on types of geothermal resources and review geologic and engineering characteristics of the geopressured-geothermal resources in Texas, (2) examine the use of geothermal fluids for TEOR, (3) characterize medium- to heavy-oil reservoirs and plays in Texas, (4) characterize medium- to heavy-oil reservoirs in the Mirando Trend in South Texas, and (5) discuss suitability of medium- and heavy-oil reservoirs in South Texas for geothermally sourced TEOR. We focus on characterizing aspects of heavy-oil reservoirs that would affect use of geopressured-geothermal fluids in a TEOR program. The study area includes five counties in South Texas (Duval, Jim Hogg, Starr, Webb, and Zapata Counties) where known geothermal fairways in the deep Wilcox Group (Gregory and others, 1980; Bebout and others, 1982) are favorably located below the shallow Mirando Trend of medium- to heavy-oil reservoirs (Galloway and others, 1983; Hamlin and others, 1989; Seni and Walter, 1990; Negus-de Wys and others, 1991).

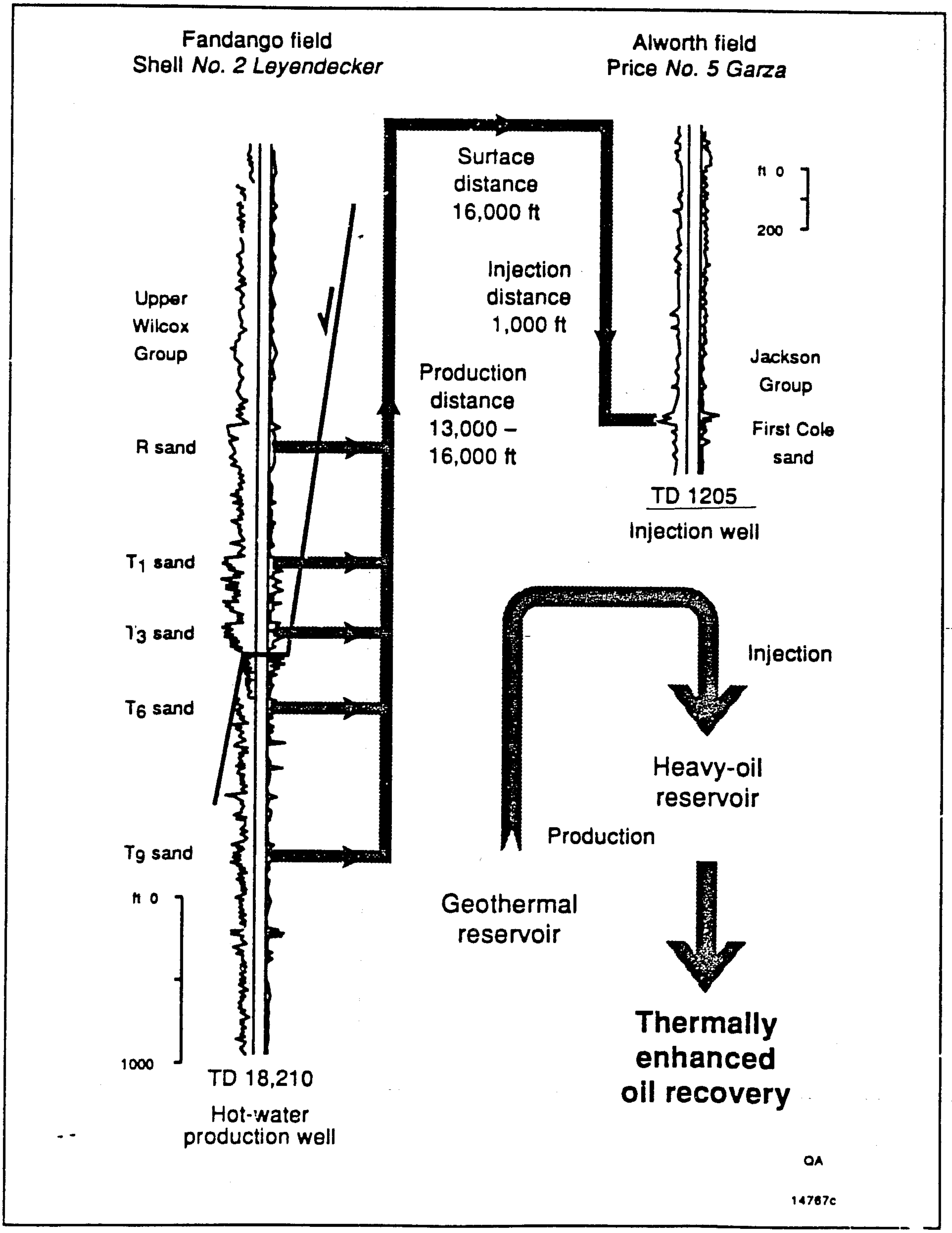


Figure 2. Schematic flow chart illustrating a geothermally enhanced oil recovery method utilizing geothermal water from reservoirs in the Wilcox to inject into shallow heavy-oil reservoirs in the Jackson Group.

Geothermal Resources in Texas

Types of Geothermal Resources

Geothermal resources can be divided into categories on the basis of the nature and origin of the resource: hydrothermal, petrothermal (hot-dry rocks), and geopressured-geothermal. The heat energy for the first two categories is generally supplied by a large body of hot rock, or magma. In a hydrothermal system, ground water becomes heated or vaporized after contacting surrounding hot rock. Such resources are considered renewable if ground water is replenished by seasonal rainfall or snowmelt. In petrothermal systems, the energy content of hot rocks is abundant but not inexhaustible. The phase of the geothermal fluid is dependent on depth and pressure and may include hot water, steam, or a mixture of the two. The Geysers, California, is an example of a vapor-dominated system that provides electrical power at a relatively low cost because the single steam phase contains no liquids that need to be separated (Barker and others, 1991).

In geopressured-geothermal systems, water trapped within a subsurface sandstone reservoir is heated by pressure and surrounding hot strata during rapid, deep burial of sediments within young sedimentary basins (Dorfman and Kehle, 1974; Bebout and others, 1978). The depositional and structural style of the Cenozoic strata along the Texas Gulf Coast favored the accumulation of thick lenses of permeable sandstone that became hydrologically isolated during burial (fig. 3). The geopressured-geothermal reservoir is sealed by relatively impermeable shale and faults. Insulating layers of thick shales encase the reservoir sandstones and retain heat within the geopressured reservoirs. The high temperature of the geopressured fluids is a result of the normal increase in temperature during burial and convective transport of heat by fluid flow. The typical geothermal gradient in the Gulf of Mexico region is 1.6°F/100 ft (25°C km^{-1}) (Bodner and others, 1985). Regionally, temperatures and geothermal gradients in the subsurface generally decrease from as high as 2.7°F/100 ft (42°C km^{-1}) along the inner coastal plain to 1.1°F/100 ft (17°C km^{-1}) offshore. In addition, gradients are higher toward the southwest, increasing by as much as 0.53°F/100 ft (8°C km^{-1}) across South Texas (Bodner and others, 1985). Abrupt increases in temperature gradients at depth commonly correspond to overpressuring (Lewis and Rose, 1970), particularly near growth faults. Gradients then decrease to nearly normal levels at greater depths.

The fluids become overpressured by partially supporting the weight of the overlying column of rock during continued burial. In a normally pressured area, fluid pressure increases with increasing depth as a function of the weight of the overlying column of water. This normally pressured area is referred to as the hydrostatic zone. In the Gulf Coast region, formation fluids are considered geopressured when fluid pressure gradients exceed 0.465 psi/ft (10.5 kPa m^{-1}) (Bebout and others, 1982). Limited fluid circulation within the overpressured interval causes the pressure gradient to rise from 0.7 to 1.0 psi/ft (15.8 to 22.6 kPa m^{-1}). Geothermal fairways are typically characterized by temperatures greater than 300°F (>149°C), fluid pressures above 0.7 psi/ft (>15.8 kPa m^{-1}), and sandstone thicknesses exceeding 300 ft (>91 m). Because geopressured-geothermal fluids are sealed within deep reservoir strata, they should be considered nonrenewable resources similar to oil and gas. Although geopressured-geothermal resources are best known in the northern Gulf of Mexico basin, geopressured basins are common in the United States and worldwide (Fertl and others, 1976).

Geopressured-Geothermal Resources: Previous Research

The Bureau of Economic Geology and the Center for Geosystems Engineering of The University of Texas at Austin have participated in a long-term research program funded by the U.S. Department of Energy (DOE) to evaluate geopressured-geothermal resources in Texas (Dorfman and Deller, 1975, 1976; Podio and others, 1976; Bebout and others, 1978, 1982; Dorfman and Fisher, 1979; Gregory and others, 1980; Bebout and Bachman, 1981; Dodge and Posey, 1981; Morton and others, 1983; Dorfman and Morton, 1985; Riggs and others, 1991). Similar programs have been funded by DOE to evaluate geopressured-geothermal reservoirs in Louisiana (Bebout and Gutierrez, 1981; McCulloh and Piño, 1981; Snyder and Pilger, 1981). As a result of this research program, a substantial body of information is now available concerning the location, distribution, and productivity of the resource. The initial research task was to assess the potential for electrical generation from the deep subsurface brines in onshore Tertiary strata. Primary goals were to locate prospective reservoirs that met the following specifications: fluid temperatures of

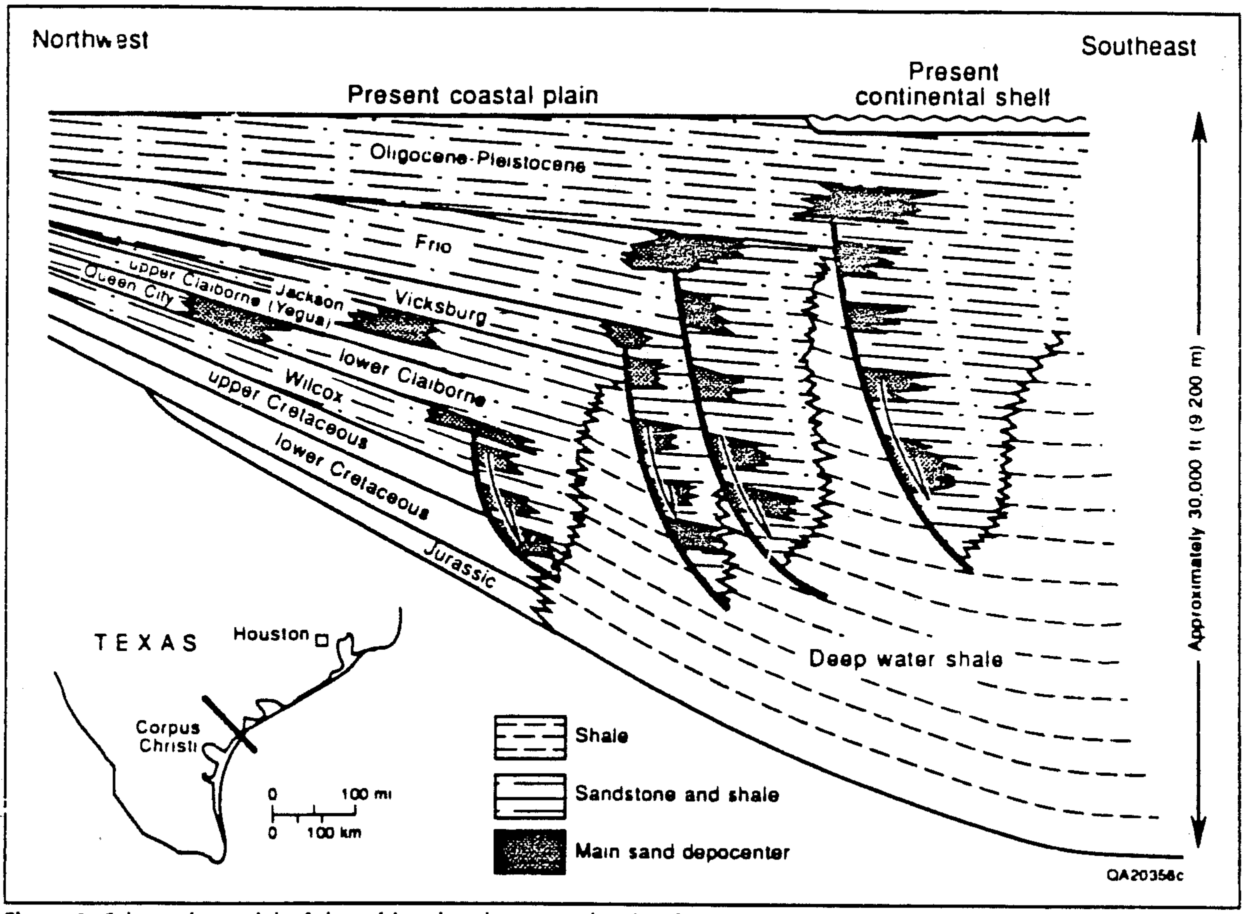


Figure 3. Schematic model of depositional and structural style of Cenozoic strata along Texas Gulf Coast (after Bebout and others, 1982).

300°F (149°C) or higher, pressure gradients higher than 0.7 psi/ft (>15.8 kPa m^{-1}), a reservoir volume of 3 mi^3 (12.5 km^3), and minimum permeability of 20 md (0.02 μm^2) (Bebout and others, 1978; Morton, 1981). The recognition that geothermal brine contained substantial dissolved natural gas focused research on quantifying the gas component. Early, optimistic projections (Jones, 1976) suggested that brines contained as much as 40 to 120 scf/bbl (7.2 to 21.6 m^3 gas m^{-3} brine). However, gas solubility was found to be a function of the salinity of the brine; high salinities reduced gas solubility (Blount and others, 1979; Gregory and others, 1980). Long-term well tests of geothermal wells indicated that gas content of the brines ranged from 20 to 34 scf/bbl (3.6 to 6.1 m^3 gas m^{-3} brine) (Negus-de Wys and others, 1991). More detailed information on regional-assessment and site-selection studies of Tertiary formations in the Texas Gulf Coast has concentrated on the Frio, Vicksburg, and Wilcox strata (Bebout and others, 1975a, b, 1976, 1978, 1982; Loucks, 1979; Gregory and others, 1980; Edwards, 1981; Morton and others, 1983; Winker and others, 1983).

Geothermal Corridors

Broad geopressured-geothermal corridors within Tertiary formations in the Gulf Coast of Texas (figs. 1 and 4) contain localized geothermal fairways or prospects that are characterized by the coexistence of high subsurface fluid temperatures (>250°F [>121°C]) and thick permeable sandstones. Geopressured-geothermal aquifers develop when thick sandstone bodies are hydrologically isolated by subsidence and rapid burial within fault blocks (Winker and others, 1983). Thick sandstone bodies provide the necessary large reservoirs for the geothermal fluids. In the Gulf Coast Basin, such corridors typically are present where deltaic, shoreline, and shelf-margin sandstones accumulated syndepositionally on the downthrown side of regional growth faults

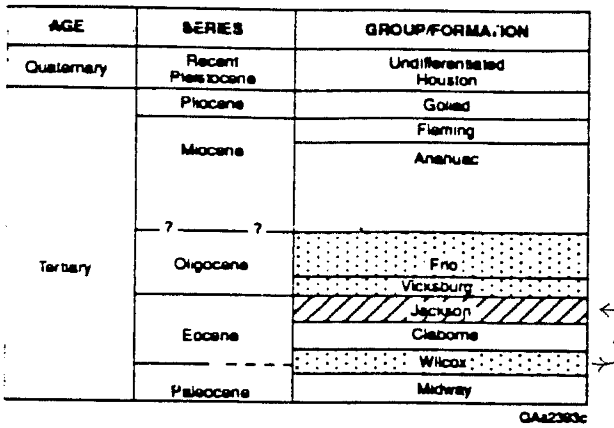


Figure 4. Stratigraphic chart of Texas Gulf Coast Cenozoic formations and groups. Geopressured-geothermal units are in stippled pattern (Bebout and others, 1978). Medium- and heavy-oil reservoirs are most common in Jackson Group (lined pattern).

(fig. 3). Belts of growth faults were formed by large-scale basinward sliding of the unstable shelf edge and by salt and shale tectonics (Ewing, 1986). In addition to determining the thickness of reservoir sandstones and the temperatures of geothermal fluids, examining permeability is necessary to characterize first-order geothermal prospectivity (Bebout and others, 1978).

Around the northern and western arc of the Gulf of Mexico depositional basin, reservoirs of geopressured-geothermal fluids lie in major sandstone-rich Tertiary sequences, including: (1) the Paleocene–Eocene Wilcox Group, (2) the Eocene Yegua Formation, (3) the Oligocene Vicksburg Group, (4) the Oligocene Frio Formation, and (5) Miocene formations. Yegua and Vicksburg strata contain geothermal resources that are less favorable for production because reservoir sandstones at suitable depths are laterally restricted or have low permeability (Loucks, 1979). In Texas, Miocene strata have not been buried to sufficient depth to host favorable geothermal resources. In Louisiana, however, Miocene strata have been buried more deeply, and a DOE geothermal design well—Gladys McCall No. 1—has been completed in Miocene strata (Clark, 1985; Durrett, 1985; Prichett and Riney, 1985). Both the Wilcox and Frio depositional units in Texas contain the thick, sandstone-rich corridors at the appropriate depth and structural setting to produce geothermal fluids (Bebout and others, 1978, 1982). Within these broad corridors are smaller geothermal fairways or prospects that contain thick potential reservoir sandstones with elevated reservoir temperatures and pressures.

Wilcox Geothermal Fairways

The Wilcox Group, together with the underlying Midway Group, constitutes the oldest thick sandstone/shale wedge within the Gulf Coast Tertiary System. The faulted downdip section of the Wilcox Group constitutes the Wilcox geothermal corridor. Sediments within the updip part of the Wilcox wedge were deposited primarily by fluvial systems. Large delta systems deposited thick, sandstone-rich sequences in the lower and upper Wilcox (Edwards, 1981; Bebout and others, 1982). Marine processes reworked some deltaic sediments and redistributed sediments alongshore in barrier bar/strandplain environments. Growth faults developed between the shoreline and shelf margin of the larger delta lobes, where thick deposits of sand and mud accumulated over unconsolidated offshore mud of the underlying sediment wedge. Subsidence along these faults isolated thick sandstone sequences, which prevented escape of pore fluids during burial.

Six geothermal fairways are identified within the corridor on the basis of sandstone distribution and reservoir temperature (fig. 5). The geology of these six geothermal fairways is represented by two Wilcox reservoir models (Bebout and others, 1982; Gregory and others, 1980). Table 1 summarizes characteristics of the reservoir models.

Model I—South Texas upper Wilcox Fairways

Model I represents upper Wilcox geopressured-geothermal reservoirs in South Texas. High-constructive lobate deltas of the upper Wilcox are growth faulted along the lower Wilcox shelf margin, forming vertically stacked reservoirs of delta-front sandstones (Edwards, 1981). Zapata, Duval, and Live Oak Fairways represent major sand depocenters associated with three delta-lobe complexes. In the Zapata Fairway, more than 1,500 ft (>457 m) of net sandstone accumulated in growth-faulted compartments (Seni and Walter, 1990). The maximum thickness of individual sandstone bodies is as much as 200 ft (61 m). To the north, in the Duval and Live Oak Fairways, individual sandstone bodies are thinner, and net sandstone packages are 300 to 700 ft (91 to 213 m) thick. Reservoir temperatures are moderate to high (250° to 471°F [121° to 244°C]) as a result of high geothermal gradients and substantial reservoir depth (fig. 6). Reservoir sandstones in the upper Wilcox are relatively continuous along strike, but numerous growth faults restrict continuity in a dip direction. Average porosity in model I fairways, which ranges from 17 to 22 percent, is favorable, but permeability is the restraint on geothermal reservoir potential in the upper

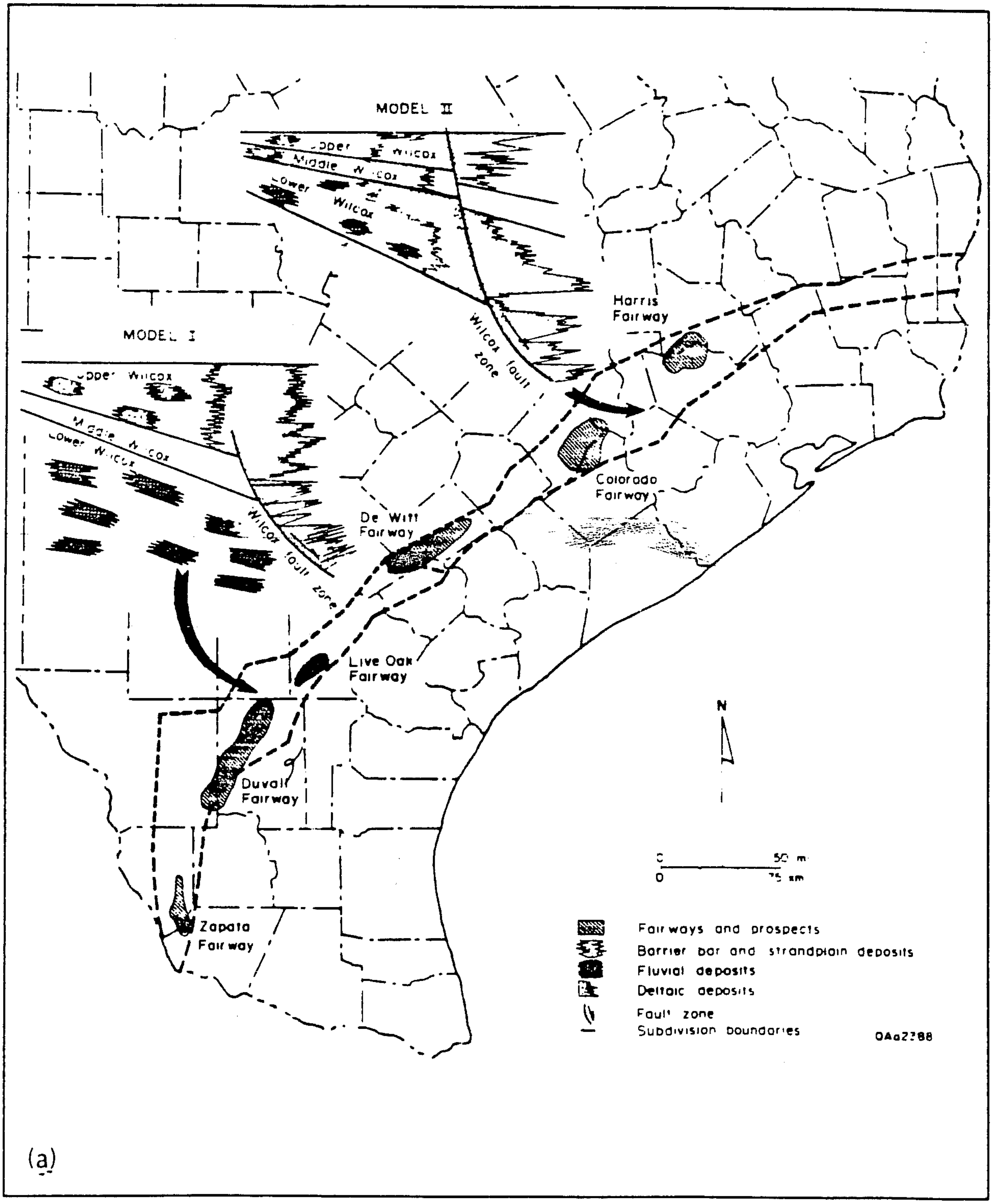
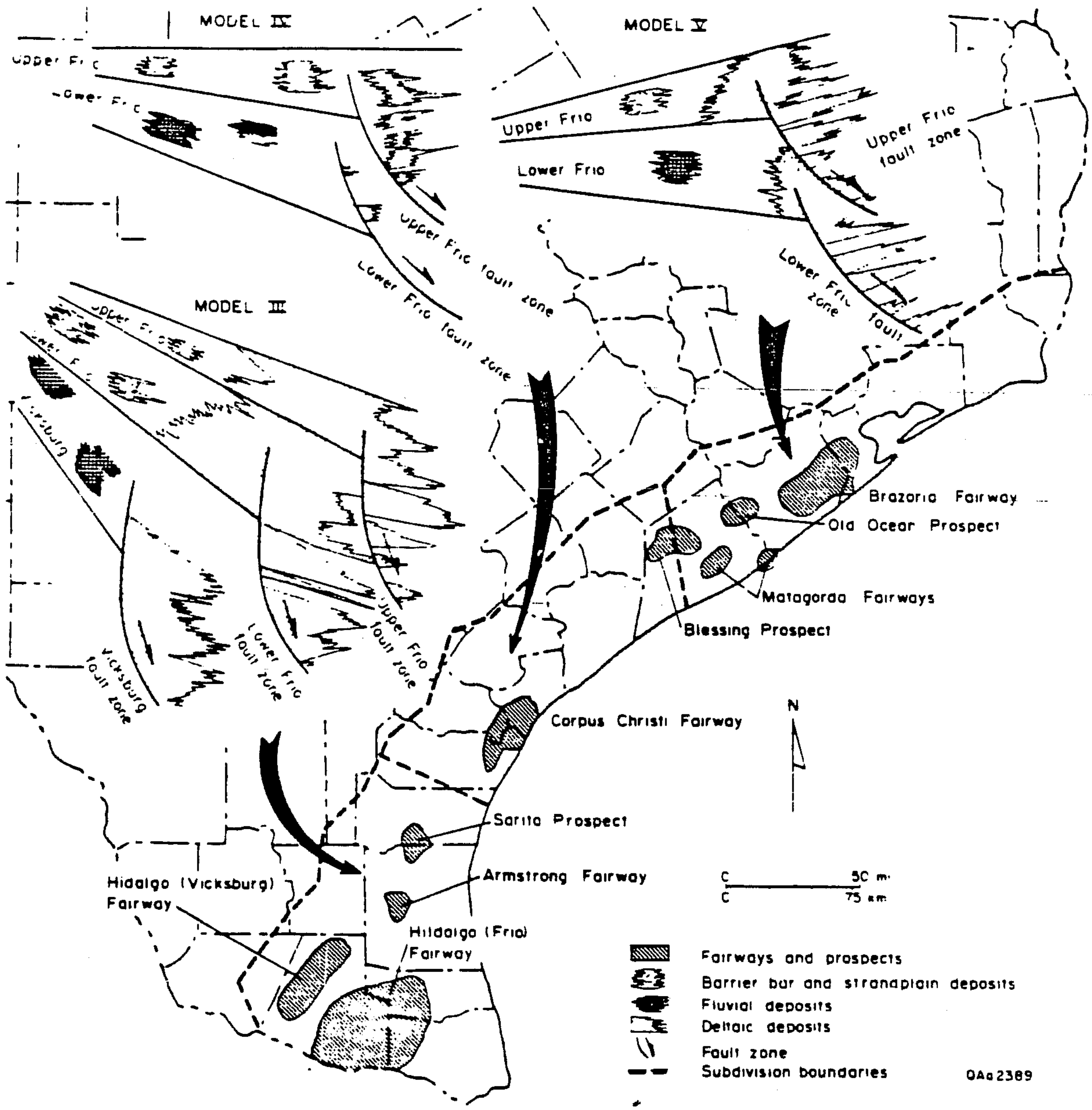


Figure 5. (a) Wilcox geopressured-geothermal reservoir models I and II and geopressured-geothermal corridor and fairways (Gregory and others, 1980; Bebout and others, 1982). (b) Frio geopressured-geothermal reservoir models II, IV, and V and geopressured-geothermal corridor, fairways, and prospects (Bebout and others, 1978; Gregory and others, 1980).


MODEL IV
MODEL V
MODEL III
Upper Frio
Lower Frio
Upper Frio fault zone
Lower Frio fault zone
Lower Frio fault zone
Vicksburg fault zone
Brazoria Fairway
Old Ocean Prospect
Matagorda Fairways
Blessing Prospect
Corpus Christi Fairway
N
Sarita Prospect
Armstrong Fairway
Hidalgo (Vicksburg) Fairway
Hidalgo (Frio) Fairway
0 50 mi
0 75 km
Fairways and prospects
Barrier bar and strandplain deposits
Fluvial deposits
Deltaic deposits
Fault zone
Subdivision boundaries
QAa 2389

(b)

Table 1. Characteristics of geopressured-geothermal reservoir models.*

Model	Sand geometry	Temperature	Pressure	Salinity	Methane solubility	Porosity and permeability	Factors limiting reservoir potential
Model I							
Upper Wilcox	Thick, laterally extensive sands	Moderate to high	Moderate to high	Low to moderate	Low to moderate	Low	Low to moderate methane solubility, low porosity and permeability
Lower Wilcox	Thin, areally extensive sands	High	High	Low	High	Very low	Thin sands, very low porosity and permeability
Model II							
Upper Wilcox	Moderately thick sands, moderately continuous	Low to moderate	Low to moderate	Low to high	Low to moderate	Low	Low porosity and permeability, low pressure in updip areas
Lower Wilcox	Thick, laterally extensive sands	High	High	High	High	Low, locally high in De Witt Fairway	Low porosity and permeability
Model III							
Upper Frio	Thick, areally limited sands	Moderate to high	Moderate to high	Low to moderate	High	Low	Areally limited sands, low porosity and permeability
Lower Frio	Thin, basal sands, laterally continuous	Very high	Very high	Low to moderate	High	Very low	Low porosity and permeability
Vicksburg	Thick, areally limited sands	High	High	Low to moderate	High	Very low	Areally limited sands, low porosity and permeability
Model IV							
Upper Frio	Thick, areally extensive sands	Low	Low	High	Low to moderate	High	Low to moderate methane solubility, low pressure
Lower Frio	Thin, areally limited sands	Moderate to high	Moderate to high	Low	Moderate to high	Low	Areally limited sands, low porosity and permeability
Model V							
Upper Frio	Thin to moderately thick sands, areal extent variable	Low to moderate	Low to moderate	Moderate to high	Low to moderate	High	Low to moderate methane solubility and pressure, low total sand volume
Matagorda Fairway	Thin, areally limited sands	High	Moderate to high	High	Moderate to high	High	Thin, areally limited sands
Brazoria Fairway	Thick, areally extensive sands	High	Moderate to high	High	Moderate to high	High	Thin, areally limited sands

*Gregory and others (1980).

10/25/93

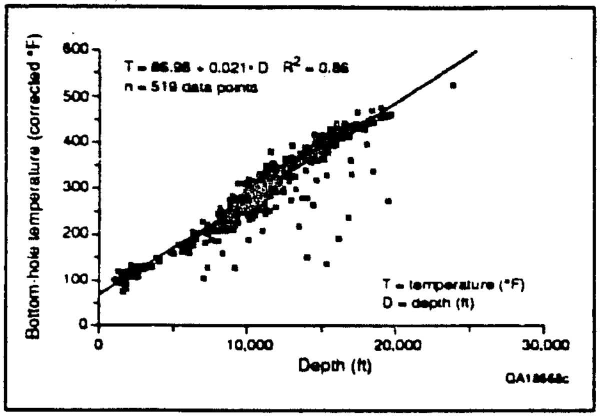


Figure 6. Plot of temperature as a function of depth for deep upper Wilcox wells in South Texas. Well log bottom-hole temperature corrected to equilibrium temperature after the method of Kehle (1971).

Wilcox. At depths where geothermal reservoirs are developed, average permeabilities are very low, ranging from 0.01 to 0.5 md (9.87×10^{-6} to 4.93×10^{-4} μm^2). Core analysis indicates that low porosities and permeabilities will limit production from potential geopressured-geothermal reservoirs (Bebout and others, 1982).

Model II— Lower Wilcox De Witt, Colorado, and Harris Fairways

Model II represents potential geothermal reservoirs in the lower Wilcox along the middle and upper Texas Coastal Plain (Gregory and others, 1980; Bebout and others, 1982). The sandstone geometry and structure in De Witt, Colorado, and Harris Fairways are characteristic of this model. High-constructive, lobate lower Wilcox deltas were extensively growth faulted when they prograded across the underlying Cretaceous carbonate-shelf margin. Delta-front sheet sands accumulated to great thicknesses across growth-fault zones. Reservoir size is limited by restricted dip extent and lateral facies changes. In the De Witt Fairway, from 400 to 1,000 ft (121 to 305 m) of net sandstone accumulated. A maximum net sandstone thickness of 1,200 to 1,600 ft (366 to 488 m) is found in the lower Wilcox in the Colorado Fairway. Maximum net sandstone thickness is more than 2,000 ft (>610 m) in the Harris Fairway. Available core data show that most permeabilities of model II sandstones in the deep subsurface are less than 1 md ($<9.87 \times 10^{-4}$ μm^2). Locally, permeabilities are highest in the De Witt Fairway, where permeabilities range from less than 2.1 to greater than 100 md ($<2.07 \times 10^{-3}$ μm^2 to $>9.87 \times 10^{-2}$ μm^2). The highest permeability is typically at the top of sandstone-bearing intervals in thick channel-fill sandstones.

Frio Geothermal Fairways

Five geothermal fairways and three prospects that lie within the Frio geothermal corridor along the Coastal Zone of Texas were simplified into three reservoir models (Bebout and others, 1978; Gregory and others, 1980) (fig. 5b). The geothermal fairways are present where contemporaneous growth faults promoted the accumulation of thick deposits of sandstone at a depth currently characterized by high subsurface temperature and pressure. A substantial body of data had been previously collected for geothermal resources in the Frio Formation in Texas (Bebout and others, 1975a, b, 1976, 1978). Reservoir-specific information relevant to the production of geothermal energy in the Frio Formation of Texas has been evaluated in one DOE design well (Morton, 1981; Morton and others, 1983; Winker and others, 1983).

Model III— Hidalgo and Armstrong Fairways

The Hidalgo and Armstrong Fairways in South Texas contain geothermal waters having temperatures from 250° to more than 300°F (121° to >149°C). Fluid temperatures in the Armstrong Fairway are relatively low. Thick, extensive sandstones characterize both fairways. Total net sandstone of more than 300 ft (>91 m) extends over an area of 50 mi² (129 km²) in the Armstrong Fairway. Numerous thick sandstone reservoirs of adequate size are present at depths greater than 13,000 ft (>3,962 m) in the Hidalgo Fairway. However, both fairways are limited by extremely low permeabilities. Near the Frio Hildago Fairway, a favorable resource fairway was mapped in the underlying Vicksburg Formation that is also characterized by low permeabilities (Loucks, 1979). Swanson and others (1976), analyzing fields producing from the geothermal zone, found that most sandstone permeabilities are less than or equal to 1 md ($\leq 9.87 \times 10^{-4}$ μm^2).

Model IV—Corpus Christi Fairway

The Corpus Christi Fairway contains high-temperature geothermal waters in the range of 300° to 340°F (149° to 171°C) in both upper and lower Frio sandstones. Updip strandplain sandstones grade downdip across closely spaced fault zones into thin sandstone beds separated by thin shale beds representing shelf and slope deposits. Although sandstone-prone zones are 400 to 900 ft (122 to 274 m) thick, individual sandstone beds

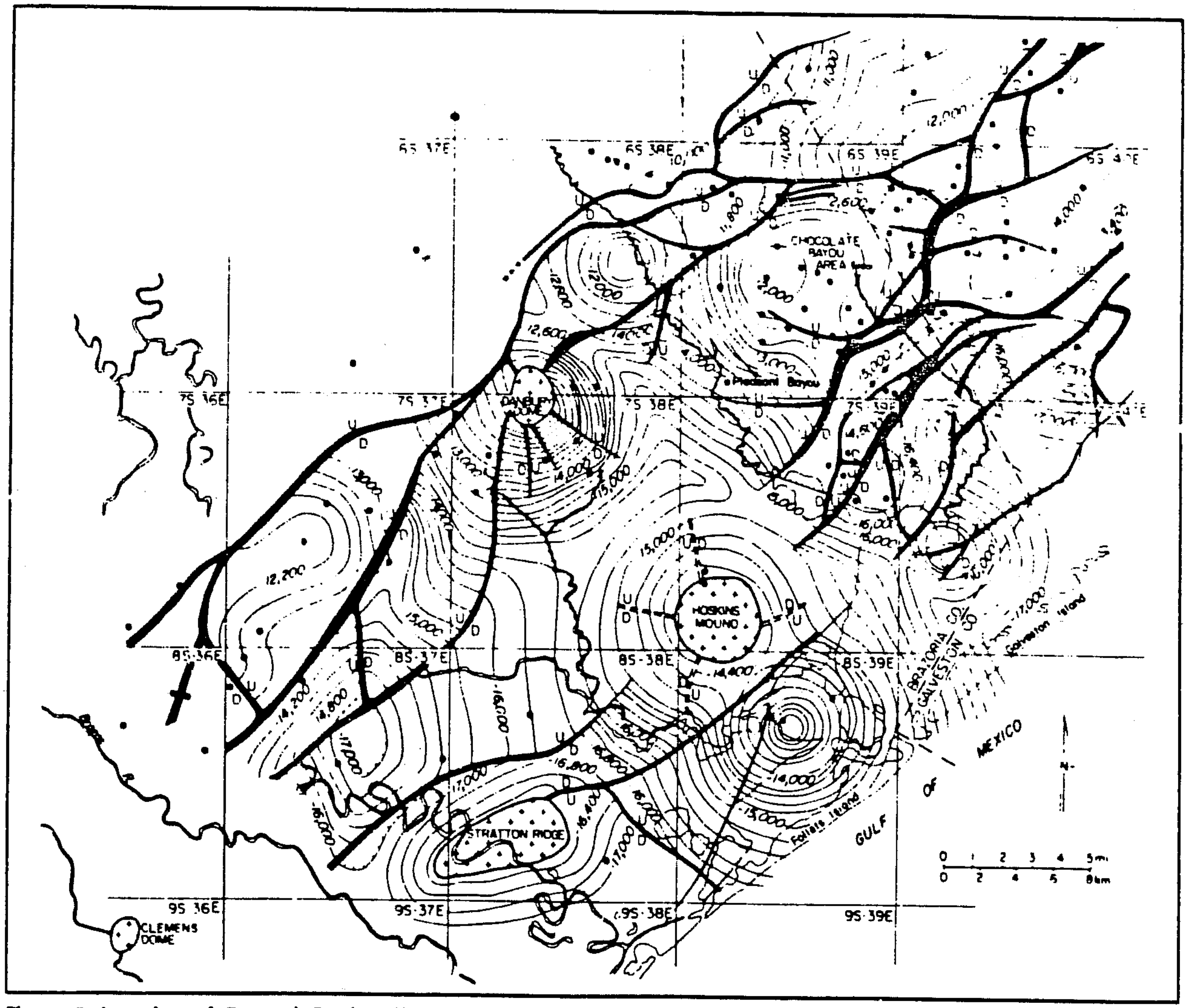


Figure 7. Location of General Crude Oil/DOE Pleasant Bayou Nos. 1 and 2 geopressured-geothermal test wells (single location for both wells is at black dot) and structure on Frio T5 marker (Morton and others, 1983).

range in thickness from 1 to 10 ft (0.3 to 3.0 m). Limited core data indicate that porosities range from 9 to 22 percent and permeabilities average less than 5.3 md ($<5.23 \times 10^{-3}$ μm^2). Local zones of high permeability (80 to 300 md [7.90×10^{-2} μm^2 to 2.96×10^{-1} μm^2]) exist at the top of some sandstones. Reservoirs in the Corpus Christi Fairway are relatively small because of restricted sand deposition and syndepositional and later faulting.

Model V—Brazoria and Matagorda Fairways

Along the upper Texas coast in Brazoria and Galveston Counties, thick, porous, and highly permeable lower Frio sandstones accumulated in the Brazoria Fairway. Bebout and others (1978) mapped and identified the Brazoria Fairway as the most favorable site for testing geopressured-geothermal resources in the Frio Formation in Texas (fig. 5b). Sandstone reservoirs in the Matagorda Fairway are thin downdip equivalents of thick sandstone reservoirs in the Brazoria Fairway (Gregory and others, 1980). The Matagorda Fairway contains sandstone reservoirs with high fluid temperatures (>340°F [>171°C]), but the reservoirs are thin and limited in lateral extent (Bebout and others, 1978). Geological characterization of potential Tertiary geopressured-geothermal reservoirs led to the Austin Bayou Prospect (within the Brazoria Fairway) as a site for the first DOE design well to evaluate the geopressured-geothermal energy resource (fig. 7).

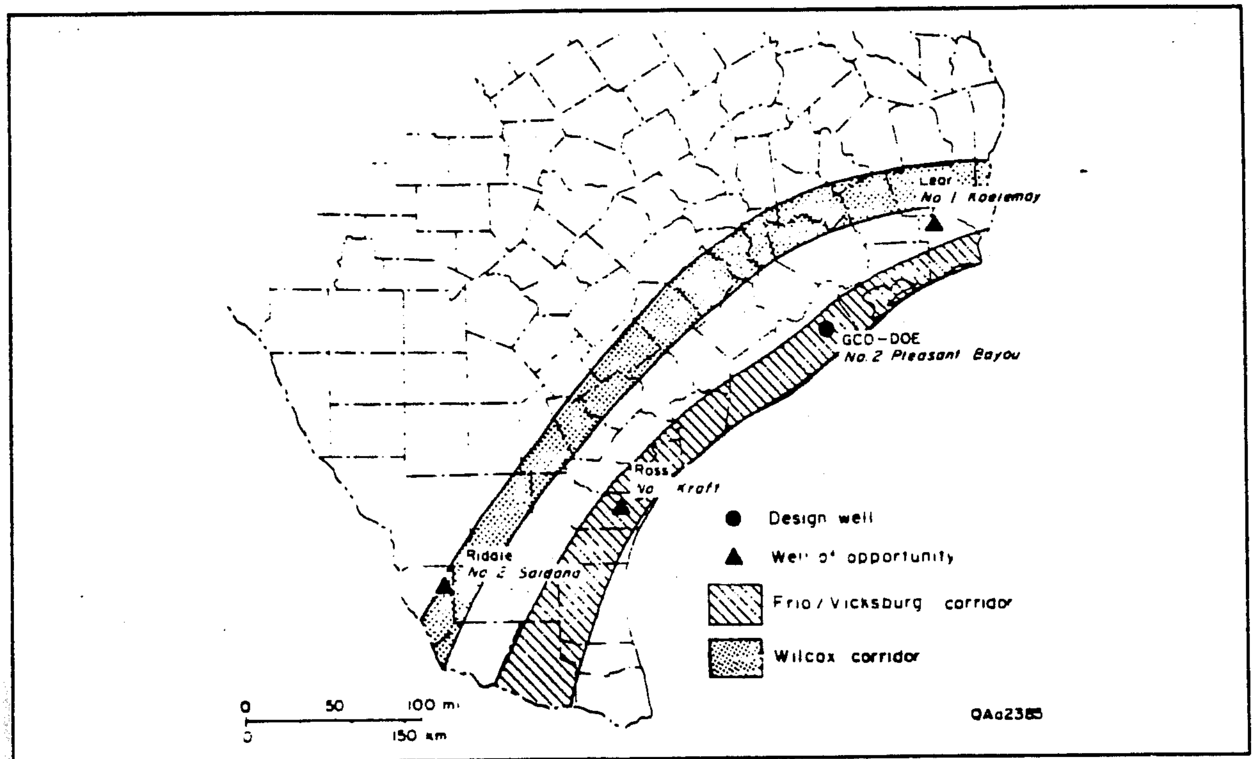


Figure 8. Location map of geopressured-geothermal corridors and geothermal test wells, Texas Gulf Coast (Morton and others, 1983).

Structural style in the Brazoria Fairway represents the interaction between deltaic sedimentation, growth faulting, and salt dome growth. Thick reservoir sandstones accumulated in a large salt-withdrawal basin that is bounded on the updip side by a major regional growth fault. Several hundred feet of potential geothermal reservoir sandstones contain fluids at temperatures higher than 300°F (>149°C). Permeability values from cores of sandstone units in the Brazoria Fairway range from less than 0.1 md (<9.87×10^{-5} μm^2) for cores with low porosities of less than 15 percent to several hundred millidarcys (<140 to 1,050 md [<1.38×10^{-1} μm^2 to 1.04 μm^2]) when porosity exceeds 20 percent. Generation of secondary porosity at reservoir depths has improved the permeability of Frio sandstones in the Brazoria Fairway (Loucks and others, 1980, 1981).

DOE Geothermal Well Testing Program

Reservoir data were collected from wells drilled in various potential geothermal reservoirs in Texas and Louisiana (Gould and others, 1981; Morton and others, 1983; Clark, 1985; Durrett, 1985; Garg and Riney, 1985; Pritchett and Riney, 1985; Rodgers and Durham, 1985; Rodgers and others, 1985). These wells include oil and gas wells drilled by industry and used for short-term tests (Wells of Opportunity program) and DOE geothermal wells used for long-term reservoir testing, characterization, and fluid production (Design Well program) (fig. 8). The short-term and long-term tests were designed to (1) document reservoir conditions, (2) define the productivity and life of the geothermal reservoir, (3) analyze geothermal fluids and dissolved gases, and (4) demonstrate potential for technical transfer to private companies.

DOE Design Well Program

Four design wells were drilled and tested (Lombard, 1985) (table 2). An additional well was drilled as a gas well and was transferred to DOE. The first design well, the General Crude–DOE Pleasant Bayou No. 1 was drilled in 1978 and completed as a disposal well after drill pipe became stuck in the geothermal section. Pleasant Bayou No. 2 was offset 500 ft (152 m) and

Table 2a. Characteristics of geopressured-geothermal test wells. DOE design wells.*

Well name	General Crude/DOE Pleasant Bayou No. 2	Technadril-F and S/DOE Gladys McCall No. 1	Dow/DOE L. R. Sweezy No. 1	Gulf-Technadril/DOE Amoco Fee No. 1	Superior Oil Co. Hulin No. 1
Age/formation	Oligocene/Frio	Miocene/lower Miocene	Oligocene/Anahuac	Oligocene/Frio	Oligocene/Frio
Unit	T5 sand	No. 8 sand	*Cibicides jeffersonensis*	*Miogypsinoides* (No. 5 sand)	*Miogypsinoides*
Depth (ft)	16,500	15,158–15,490	13,340	15,387–15,414	21,546
Thickness (ft)	60	300	50	27	500
Bottom-hole pressure (psi)	11,050	12,783	11,410	12,052	18,500
Flowing pressure (psi)	3,000	2,000	—	4,749	3,500
Bottom-hole temperature (°F)	301	298	237	279	360
Surface temperature (°F)	292	268	—	—	330
Gas/water ratio	23.7	27	17.5	20.9	34
Percent methane	85	85	—	—	93
Percent CO_2	10.5	10	10	—	4
Reservoir size (Bbbl)	8	4	—	—	14
Total dissolved solids (mg/L)	131,320	95,000	—	—	195,000
Cl (mg/L)	70,000	57,000	—	—	115,000
Porosity (%)	19	23.8	27	20	—
Permeability (md)	200	64	6–1,526 (817 on buildup)	42–140	—
Sustained flow rate	20,000	19,837	9,800	2,046–2,648	15,000
Long-term production (MMbbl)	19.5	27.3	—	1.1	—
Limiting factors	Well sanding when production >20,000 bbl	—	Well sanding when production >10,000 bbl	High production rates not sustainable; reservoir barriers	No long-term tests

*Modified from Klauzinski (1981), Morton (1981), Morton and others (1983), Clark (1985), Garg and Riney (1985), Peterson (1985), Negus-de Wys and others (1990), and Eaton Operating Company (1991). Dashes indicate information is not available.

Table 2b. Characteristics of geopressured-geothermal test wells. DOE Wells of Opportunity.*

Well name	Riddle Saldana No. 2	Lear Koelemay No. 1	Rosa Kraft No. 1	Wainoco Oil and Gas P. R. Girouard No. 1
Age/formation	Eocene/upper Wilcox	Eocene/Yegua	Oligocene/Frio	Oligocene/upper Frio
Unit	First Hinnant	Leger sand	Anderson sand	*Marginulina texana*
Depth (ft)	9,745–9,835	11,590–11,729	12,750	14,720-14,827
Gross sand thickness (ft)	90	139	120	107
Net sand thickness (ft)	79	77	109	91
Bottom-hole pressure (psi)	6,627	9,450	10,986	13,203
Shut-in surface pressure (psi)	2,443	4,373	9,507	6,695
Bottom-hole temperature (°F)	300	260	263	274
Gas/water ratio	47–54	30 (plus gas cap)	—	40 (estimate)
Total dissolved solids (mg/L)	13,000	15,000	23,000	23,500
Porosity (%)	20	26	23	26
Permeability (md)	7	85	39	—
Sustained flow rate	1,950	—	34	15,000
Limiting factors	Tight	Restricted reservoir	Damaged reservoir	Restricted reservoir

*Modified from Klauzinski (1981), Morton (1981), Morton and others (1983), Clark (1985), Garg and Riney (1985), Peterson (1985), Negus-de Wys and others (1990), and Eaton Operating Company (1991). Dashes indicate information is not available.

successfully completed to 16,500 ft (5,029 m) in 1979 (Bebout and others, 1978; Morton and others, 1983). The DOE Pleasant Bayou No. 2, in Brazoria County, Texas, is the only well in the geothermal-geopressured program that has successfully produced energy. An experimental hybrid power system (Hughes and Campbell, 1985; Eaton Operating Company, 1991) produced approximately 1 megawatt per day through (1) a binary-cycle turbine utilizing heat from geothermal brines to vaporize isobutane and (2) gas-engine combustion heat from separated natural gas. Natural gas from this well was also sold to a pipeline. This test extended from September 1989 to June 1990. The DOE Pleasant Bayou No. 2 sustained production of 20,000 to 23,000 bbl/d (3.68×10^{-2} $m^3 s^{-1}$ to 4.23×10^{-2} $m^3 s^{-1}$) of brine at a well-head temperature of 268°F (131°C) (Eaton Operating Company, 1991). Approximately 20 MMbbl (~3.18×10^6 m^3) have been withdrawn, and 39 MMcf (1.10×10^6 m^3) of gas were extracted from the well's estimated 7.8 Bbbl (1.24×10^9 m^3) fluid reservoir (Eaton Operating Company, 1991). The test facility successfully demonstrated the ability to convert multicomponent geopressured-geothermal energy into useful power. However, the costs of electricity and gas produced from the test were not economically viable when compared with that produced from conventional energy resources.

DOE Wells of Opportunity Program

The DOE Wells of Opportunity program used existing oil and gas wells for short-term reservoir tests. Six conventional oil and gas wells that were tested in the program during 1980 and 1981 sustained fluid production rates of 1,9‹ : to 15,000 bbl/d (3.59×10^{-3} $m^3 s^{-1}$ to 2.76×10^{-2} $m^3 s^{-1}$) from conventional 2 3/8- to 3 1/2-inch (6.0- to 8.9-cm) tubing (Klauzinski, 1981). Riddle No. 2 Saldana in Martinez field, Zapata County, South Texas, is a well of opportunity that has tested the First Hinnant sandstone (upper Wilcox), which correlates with the Live Oak delta complex in McMullen and Live Oak Counties (Morton and others, 1983). This well provides the most direct data on the geothermal well productivity of the upper Wilcox in South Texas. The sandstone has good reservoir continuity and poor to excellent reservoir quality. For the Riddle No. 2 Saldana, average porosity from the sonic log was 16 percent, average permeability was 7 md (6.91×10^{-3} μm^2), salinity was 13,000 ppm TDS, maximum temperature was 300°F (149°C) (Morton and others, 1983), and maximum flow rate was 1,950 bbl/d (3.59×10^{-3} $m^3 s^{-1}$) (table 2).

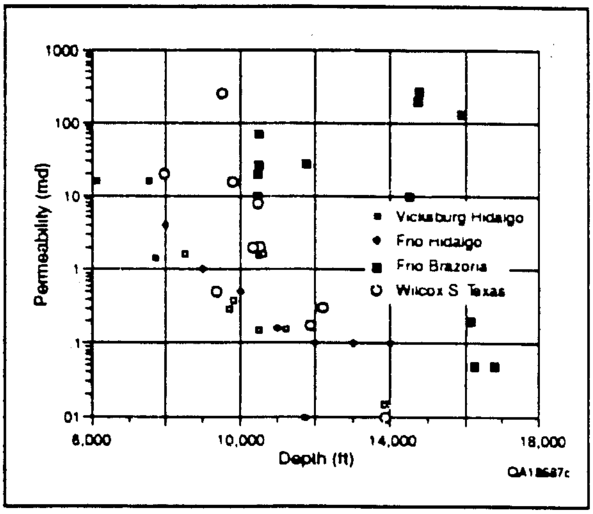


Figure 9. Average permeability plotted as a function of depth for various Texas geothermal corridors: Wilcox (Klauzinski, 1981; Bebout and others, 1982; Morton and others, 1983); Vicksburg (Swanson and others, 1976; Loucks, 1979); and Frio (Bebout and others, 1978; Morton and others, 1983).

Average permeability data from previous geopressured-geothermal research programs (fig. 9) represent permeabilities derived from diamond core, sidewall core, drill-stem tests, pumping tests, and median values averaged from many samples. These undesirable variations in measurement techniques impose an additional scatter to data that characteristically have a wide natural dispersion. Despite the scatter in the data, there is a clear distinction between the relatively low permeabilities of Vicksburg, Frio, and Wilcox strata in South Texas and the extraordinarily high permeabilities measured in the Frio in the Brazoria Fairway. In the South Texas area, where Wilcox and younger Tertiary strata are deeply buried (11,000 to 14,000 ft [3,353 to 4,267 m]) in the hot geothermal zone, typical permeabilities range from less than 0.01 to 1 md (<9.87×10^{-6} μm^2 to 9.87×10^{-4} μm^2). For instance, Morton and others (1983) reported that average permeability was 17 md (1.68×10^{-2} μm^2) in the First Hinnant sandstone (17 measurements) over a depth range of 9,720 to 9,840 ft (2,963 to 2,999 m) at the Riddle No. 2 Saldana. In contrast, at Pleasant Bayou No. 2, average permeabilities are 230 md (2.27×10^{-1} μm^2) in the Andrau Sand (27 measurements) over a depth range of 14,484 to 14,766 ft (4,415 to 4,501 m) (Morton and others, 1983, p. 54–57). Rosita field in Duval County, an upper Wilcox gas field from which abundant

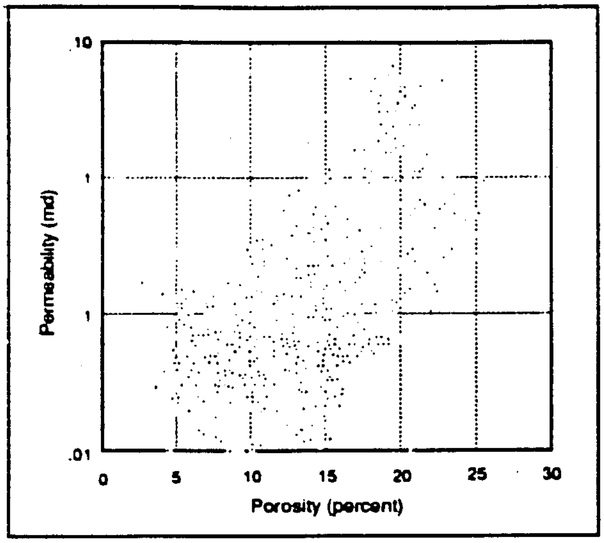


Figure 10. Permeability (unstressed air permeability) versus porosity in upper Wilcox gas wells, Duval County, Texas.

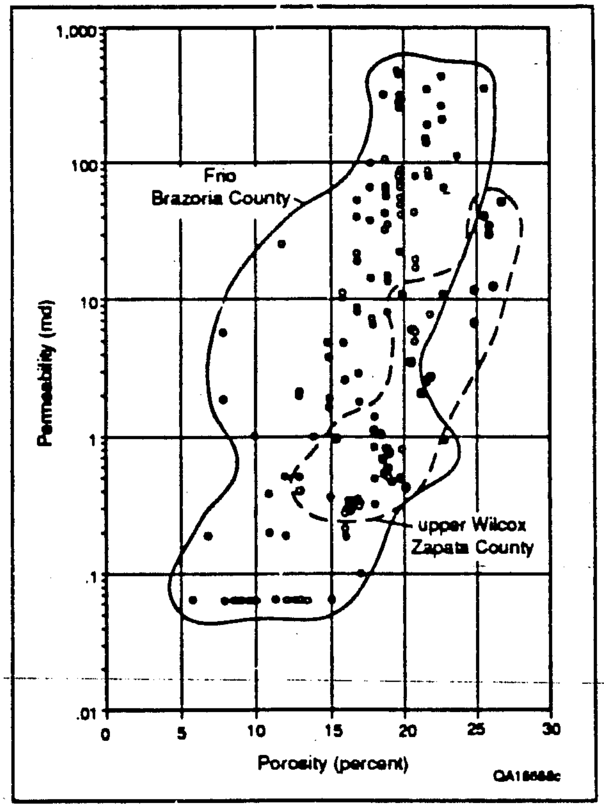


Figure 11. Permeability (unstressed air permeability) versus porosity, Frio Chocolate Bayou field, Brazoria County, Texas, and an upper Wilcox field in Zapata County, South Texas.

porosity/permeability data are available, shows that in the deepest and hottest reservoirs, most permeability values are less than 1 md ($<9.87 \times 10^{-4}\ \mu m^2$) (fig. 10). Permeabilities from the Frio Pleasant Bayou No. 2 geothermal well in Brazoria County, when compared with those from the upper Wilcox Fandango field in Zapata County (fig. 11), are typically one to two orders of magnitude greater for a given constant porosity.

Summary of Geopressured-Geothermal Resources in Texas

The thick reservoir sandstones and locally high porosity and permeability characterize reservoirs of model V in the Frio Formation of the central Texas Gulf Coast as the most favorable for production of geopressured-geothermal resources in Texas. Both the Frio Formation and Wilcox Group contain sandstone reservoirs of sufficient thickness and temperature to be viable geothermal resources. Maximum temperatures of thick reservoir sandstones in the Frio are approximately 300°F (~149°C). Locally, upper Wilcox reservoirs (model I) contain geothermal fluids in excess of 450°F (>232°C) and thick reservoir sandstones. The favorable trend of high fluid temperature, low salinity/high gas saturation, and thick reservoir sandstone in the South Texas Wilcox Group must be balanced against the consistent trend of decreasing porosity and permeability with depth.

The limiting factor affecting geothermal productivity is the low permeability of potential reservoir sandstones. Low permeability is endemic for South Texas Wilcox, Frio, and Vicksburg Fairways (Swanson and others, 1976; Bebout and others, 1978, 1982; Loucks, 1979). Comparison of porosity/permeability relationships between South Texas Wilcox reservoirs and ideally favorable Frio reservoirs along the central Texas Gulf Coast indicates that the Frio reservoirs at similar reservoir depth typically have permeabilities that are one to two orders of magnitude greater. The abundance of unstable volcanic rock fragments in South Texas favors a burial diagenesis pathway that results in reduction of original primary porosity by cementation. Along the middle Texas coastal area, secondary porosity by feldspar dissolution in the deep subsurface (Loucks and others, 1980, 1981; Milliken and others, 1981) has enhanced porosity and permeability of deeply buried sandstones.

Direct Use of Geothermal Fluids for Improved Oil Recovery

The role of hot-water flooding in the mobilization of heavy oil is poorly documented (DuBar, 1990), and relatively few field applications have been designed to assess the effectiveness of hot-water floods to increase production of heavy crude. Important exceptions are the pilot test in the Schoonebeek field, the Netherlands (Dietz, 1972), and the Loco field in southern Oklahoma (Martin and others, 1972). According to DuBar (1990), these two tests demonstrated that, although the process was more complicated than originally anticipated, hot-water flooding could increase heavy-oil production. Currently, Amoco Production Company is using geothermal fluids in a hot-water flood of oil reservoirs in Wyoming (Lunis, 1990).

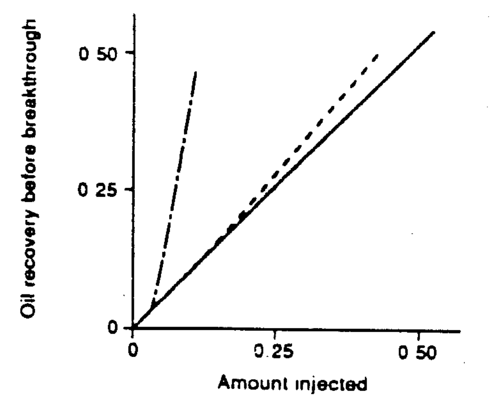


Figure 12. Oil recovery before breakthrough of water versus the amount of water injected: curve A—conventional (cold) water flood, curve B—hot water flood, and curve C—steam flood. Modified from Burger and others (1985); printed by permission of the publisher.

Hot-Water Flooding

Raising the temperature of the reservoir and the oil is the primary method employed in thermal-recovery techniques for decreasing in situ viscosities and increasing production from heavy-oil reservoirs. Hot-water flooding is one method of heating the reservoir to decrease the oil viscosity and thus improve the displacement efficiency over that obtainable from conventional waterfloods (Craig, 1971). Hot-water flooding is essentially a displacement process in which both hot and cold water mobilize oil. A hot-water flood, whether using geothermally heated fluids or conventionally heated water, involves the flow of two phases: water and oil. Steam and combustion processes include a third, gaseous, phase. The displacement efficiency of hot water is greater than that of cold water, but much less than that of steam (fig. 12). Hot water has a lower transport capacity and sweep efficiency than steam injection (Burger and others, 1985).

Burger and others (1985) showed schematically how (1) thermal expansion, (2) viscosity reduction, (3) wettability, and (4) oil/water interfacial tension affect displacement efficiency of crudes of varying oil density (fig. 13). Qualitatively, viscosity reduction is the most important mechanism that contributes to increasing displacement efficiency of heavy crudes, whereas thermal expansion is more important in displacing light crudes. Burger and others (1985) recognized three principal zones that develop in a reservoir flooded by hot water (fig. 14):

Zone 1: At each point in the heated zone, the temperature increases with time, which reduces the residual oil saturation. The temperature within the reservoir decreases with increasing lateral distance from the injection well. In addition, expansion of fluids and matrix leads to a reduction of the specific gravity of the oil left in the pore space at the same saturation.

Zone 2: Oil is being displaced by water that has cooled to the temperature of the formation. The oil saturation at any point in the zone will decrease with time, and under certain conditions may reach residual saturation corresponding to the prevailing temperature in the zone. The oil saturation will then increase with increasing lateral distance from the injection well.

Zone 3: Reservoir conditions in this zone are consistent with the ambient conditions that existed before the hot fluids were injected. In contrast to the three zones that develop during injection of hot water, four zones develop during steam injection: (1) the steam zone, (2) the condensation zone, (3) the hot-water zone, and (4) the unaffected zone (Burger and others, 1985).

Heavy-oil reservoirs are the focus of the colocation research program because literature and laboratory data

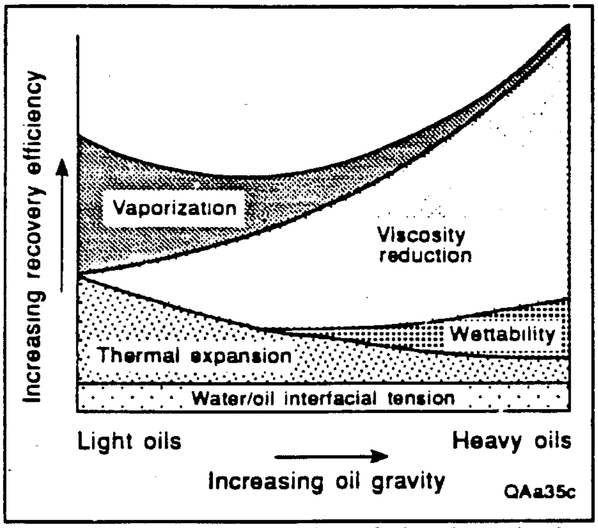


Figure 13. Relative contribution of viscosity reduction, vaporization, thermal expansion, wettability, and water/oil interfacial tension to the improvement of oil displacement by hot water or steam. In oils with high densities, reduction in viscosity is the most important process. Modified from Burger and others (1985); printed by permission of the publisher.

indicated that heavy oil from these reservoirs would exhibit a greater viscosity reduction during hot-water flooding than would light oil (Tissot and Welte, 1984; Negus-de Wys and others, 1991). Traditionally, oil is classified primarily by its API gravity, and a heavy oil has an API gravity greater than 10° and less than or equal to 20° (Lane and Garton, 1925; Smith, 1968; Tissot and Welte, 1984). The boundary of 20° API gravity between heavy and medium oil, however, is not universally accepted. North (1985) used 22° as the boundary between heavy and medium oil. In some areas characterized by abundant light oil, such as the Arabian Peninsula, oil below 27° is considered heavy (North, 1985).

In this report, heavy oil is defined as having API gravity between 10° and 20°, viscosities of 100 to 10,000 centipoise (cP) (1 to 100 g cm^{-1} s^{-1}) at reservoir conditions, and specific gravity of 0.93 to 1.0 g cm^{-3} (Tissot and Welte, 1984). Medium oil is defined as having API gravity between 20° and 25°. Dense, viscous oils having low API gravities and high viscosity characterize the heavy oils reported in this study. Viscosity, the internal friction of a fluid that causes resistance to flow, is defined by force × distance / area × velocity. Oil viscosities are commonly unavailable in public sources of information, whereas oil densities and API gravities are typically reported. Viscosities vary directly with densities, and thus oil viscosity is a function of the number of carbon atoms and the amount of gas dissolved in the oil (North, 1985). According to Tissot and Welte (1984), API gravity is strongly correlated (correlation coefficient of 0.916 for high-sulfur crude oils) to log viscosity. According to Negus-de Wys and others (1991), for 20° API-gravity oil at a reservoir temperature of 86°F (30°C), viscosity can be reduced by an order of magnitude from 100 to 10 cP (1.0 to 1.0 × 10^{-1} g cm^{-1} s^{-1}) if reservoir temperature is increased to 212°F (100°C). The operational difficulty is in distributing heat throughout the reservoir and avoiding channeling of injected hot fluids. The disadvantages of hot-water flooding are substantially mitigated if an ample supply of geothermally heated water exists near a heavy-oil reservoir.

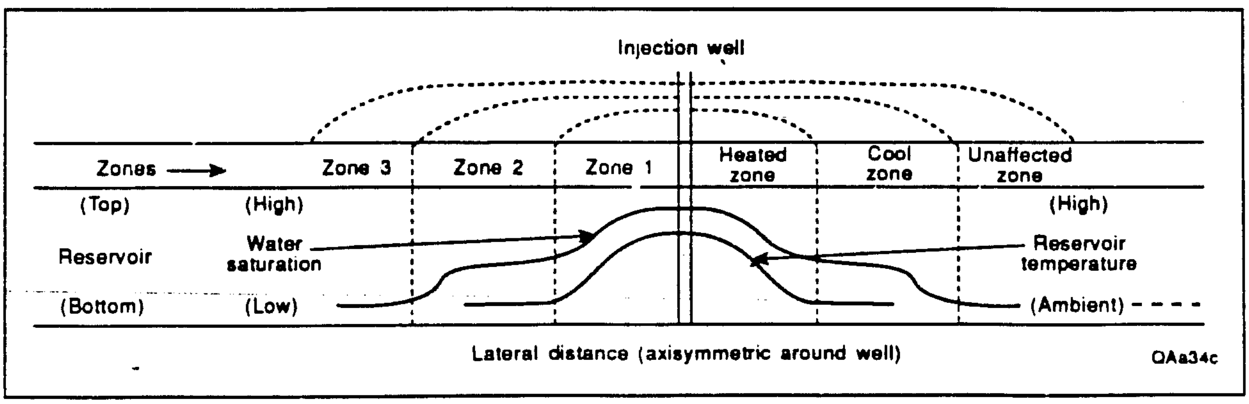


Figure 14. Displacement zones, water saturation, and temperature profiles around a well bore during injection of hot water into a heavy-oil reservoir. Zone 1—heated zone, zone 2—cool zone, and zone 3—unaffected zone. Excludes the effects of vaporization of the light fractions of the oil, thermal overrunning within the reservoir, and reservoir heterogeneities. Modified from Burger and others (1985); printed by permission of the publisher.

Heavy Oil in Texas

Heavy-oil fields compose approximately 25 percent of the 100 largest fields in the United States in terms of 1980 reserves (Interstate Oil Compact Commission, 1984). Reservoirs containing heavy oil are concentrated in California and Texas; the two states respectively contain 32 and 31 percent of the nation's 1,108 heavy-oil reservoirs (Interstate Oil Compact Commission, 1984). Heavy-oil fields in California have produced more than 12 Bbbl (>1.91 × 10^9 m^3) of oil (Interstate Oil Compact Commission, 1984), and thermal recovery techniques, such as steam flooding or cyclic steam injection, are commonly used to improve recovery from these fields. Ten percent of the large oil reservoirs in Texas ("large" reservoirs are defined as those having a cumulative production greater than 10 MMbbl [>1.59 × 10^6 m^3]) produce medium and heavy oil (Galloway and others, 1983). In Texas, medium- and heavy-oil reservoirs, like light-oil reservoirs, are typically produced without thermal recovery techniques. These medium- and heavy-oil reservoirs represent an underutilized resource because high oil viscosities result in low average recovery efficiencies of 20 to 35 percent (Galloway and others, 1983; Interstate Oil Compact Commission, 1984). In contrast, recovery efficiencies for light-oil reservoirs average 50 percent (Galloway and others, 1983).

Data Sources

To assess the potential of geothermal fluids for enhanced recovery of heavy oil, a review was conducted during this study to determine the distribution of medium- and heavy-oil reservoirs in Texas. The Railroad Commission of Texas' annual report is the primary source of public information on oil and gas reservoirs in Texas. Although the Railroad Commission of Texas does not report reserves, reservoir data include depth, API gravity, current annual production, and cumulative production.

Galloway and others (1983) selectively analyzed large Texas oil reservoirs with production of greater than 10 MMbbl (>1.59 × 10^6 m^3) and grouped reservoirs into geologically defined plays. Reservoir statistics for the large oil reservoirs in Texas that originally were tabulated in Galloway and others (1983) were computerized and updated (cumulative production statistics current to January 1, 1990) by Tyler and others (1991). The 460 large oil reservoirs studied by Galloway and others (1983) represent approximately 70 percent of the total state oil production. Logically, these large reservoirs represent the most favorable resource targets for TEOR because their larger resource base, in comparison with that of small oil reservoirs, is needed to support the additional infrastructure expense of developing geothermal fluids. Previous compilations of the heavy-oil (and tar sands) resources in the United States include Ball and Associates (1962) and the Interstate Oil Compact Commission (1984). The Interstate Oil Compact Commission (1984) provided detailed field reports on major tar sands in the United States (typically fields with API gravity <10°) and listed public information on the heavy-oil fields (API gravity between 10° and 20°).

Texas Medium- and Heavy-Oil Plays

Plays containing multiple large medium- and heavy-oil reservoirs are concentrated along the Texas Gulf Coast and in the East Texas Basin (fig. 15). The play, API gravity, depth, and cumulative production for all medium- and heavy-oil reservoirs in Texas that have exceeded 10 MMbbl (>1.6 × 10^6 m^3) cumulative production are listed in table 3 (Tyler and others, 1991). These medium- and heavy-oil reservoirs account for 8.4 percent of the total oil production from the large reservoirs in Texas (table 4). The API gravity of the large reservoirs is strongly dependent on reservoir depth (fig. 16). The dominant trend is for the oils to become heavier (lower API gravity) and more viscous with decreasing depth. All heavy-oil reservoirs are shallower than 6,000 ft (<1,828 m) and have an average depth of less than 3,200 ft (<975 m). The average depth of the medium-oil reservoirs is 3,500 ft (1,067 m). The average size of the heavy-oil reservoirs (125 MMbbl [2.0 × 10^7 m^3]), on the basis of cumulative production (table 2), is large, reflecting the few (9) large heavy-oil reservoirs and the inclusion of one supergiant reservoir—Hawkins Woodbine—that has a cumulative production of 814 MMbbl (1.3 × 10^8 m^3).

The gravity of oil varies among a group of related reservoirs and even between wells within a single reservoir. Despite this variability, reasonable trends are illustrated in figure 17 for average API gravity and depth of all reservoirs within plays of the large Texas oil reservoirs. As in individual reservoirs, the average API gravity in shallow plays is lower than the average API

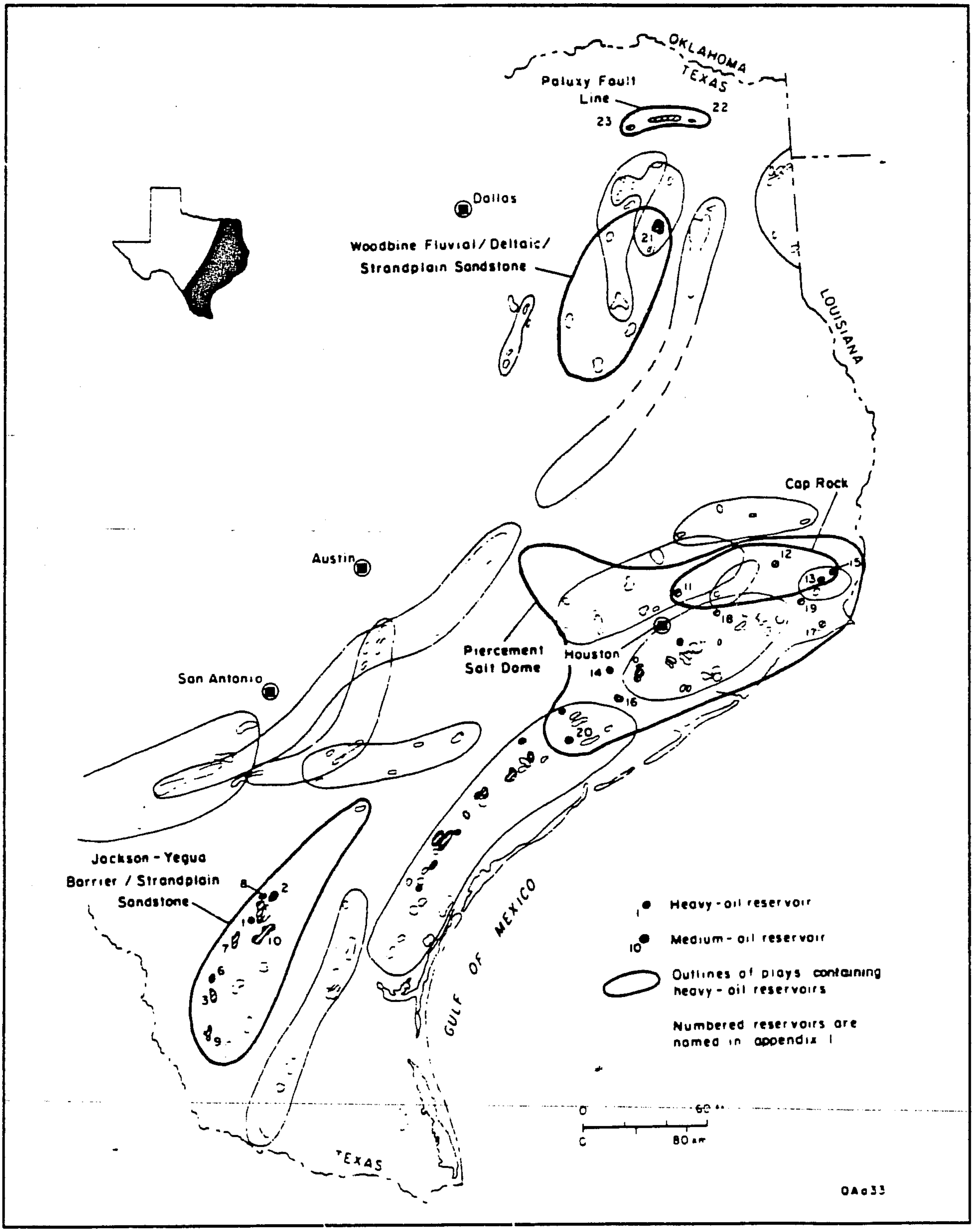


Figure 15. Map of oil plays in Texas containing medium- to heavy-oil reservoirs. Modified from Galloway and others (1983). Names of fields and reservoirs are listed in appendix 1.

Table 3. Production statistics from large oil reservoirs in Texas.*

Field and reservoir	Play	API gravity (degrees)	Depth (ft)	Cumulative production (MMbbl)
Big Creek	Salt Dome	18	4,500	25.173
Olson	San Andres/Ozona Arch	18	1,800	14.04
Pewitt Ranch Paluxy	Paluxy Fault	19	4,300	23.378
Port Neches	Salt Dome	19	6,000	24.568
Toborg, Cretaceous	Yates Area	19	500	41.231
Hawkins, Woodbine	Woodbine Sandstone	19	4,500	814.212
Lundell	Jackson/Yegua	19	1,500	10.4
Seven Sisters, G. W.	Jackson/Yegua	20	2,330	55.955
Aviators, Mirando	Jackson/Yegua	21	1,700	10.37
Govt. Wells N	Jackson/Yegua	21	2,200	80.026
Govt. Wells S	Jackson/Yegua	21	2,300	18.148
Mirando City, Mirando	Jackson/Yegua	21	1,600	12.302
Sulphur Bluff, Paluxy	Paluxy Fault	21	4,500	32.136
Damon Mound	Salt Dome	21	3,800	16.941
Houston S, Miocene	Frio Deep-Seated Dome	22	4,000	14.9
Humble, Cap Rock	Cap Rock	22	1,200	168.134
Lopez First, Mirando	Jackson/Yegua	22	2,200	31.352
Piedre Lumbre, G. W.	Jackson/Yegua	22	1,900	21.128
Sour Lake, Cap Rock	Cap Rock	22	600	132.749
Spindletop, Cap Rock	Cap Rock	22	800	154.681
Talco, Paluxy	Paluxy Fault	22	4,300	279.615
Bloomington, 4600	Frio Barrier/Strandplain	23	4,600	31.568
Escobas, Mirando	Jackson/Yegua	23	1,200	13.067
Hoffman, Dougherty	Jackson/Yegua	23	2,000	48.805
Taft, 4000	Frio Barrier/Strandplain	23	4,000	25.284
Clam Lake	Salt Dome	23	1,179	12.79
Bonnie View	Frio Barrier/Strandplain	24	4,500	19.624
Gannado W, 4700	Frio Barrier/Strandplain	24	4,700	27.6
Greta, 4400	Frio Barrier/Strandplain	24	4,400	133.232
Lake Pasture, H-440 S	Frio Barrier/Strandplain	24	4,500	51.815
Placedo, 4700 sand	Frio Barrier/Strandplain	24	4,700	43.076
Tom O'Connor, 4400	Frio Barrier/Strandplain	24	4,400	14.22
Tom O'Connor, 4500	Frio Barrier/Strandplain	24	4,500	18.895
Weigang, Carrizo	Wilcox Fluvial/Deltaic	24	3,900	11.193
West Ranch, Greta	Frio Barrier/Strandplain	24	5,100	99.237
Westbrook	East Shelf Permian Carb.	24	2,900	90.737
Barbers Hill	Salt Dome	24	7,200	131.067
Maurbro, *Marginulina*	Frio Barrier/Strandplain	25	5,200	26.031
McFaddin, 4400	Frio Barrier/Strandplain	25	4,400	30.334
Pickett Ridge	Frio Barrier/Strandplain	25	4,700	16.077
Quitman, Eagle Ford	Cretaceous Sandstone	25	4,200	10.654
Thompson, Frio	Frio Deep-Seated Dome	25	5,400	360.417
Thompson S, 4400	Frio Deep-Seated Dome	25	4,400	24.798
Thompson S, 5400	Frio Deep-Seated Dome	25	5,300	10.7
Fannett	Salt Dome	25	8,350	53.88
Markham	Salt Dome	25	4,385	17.917

*Statistics current as of January 1, 1990. List generated from data in Tyler and others (1991).

Table 4. Comparative statistics of large heavy-, medium-, and light-oil reservoirs in Texas.*

Category	Reservoirs (number)	Total production (MMbbl)	Production (percentage)	Average reservoir production (MMbbl)	Average depth (ft)
Heavy oil	8	999	2.5	125	3,178
Medium oil	38	2,296	5.8	60	3,506
Light oil	415	36,046	91.6	87	6,173
Total	461	39,340	100.0	85	5,940

*List generated from data in Tyler and others (1991).

gravity in the deeper plays. Five plays containing medium- and heavy-oil reservoirs are significant for TEOR: Jackson-Yegua Barrier/Strandplain Sandstone, Cap Rock, Piercement Salt Domes, Paluxy Fault Line, and Woodbine Fluvial/Deltaic/Strandplain Sandstone. Of these five plays, four are characterized by a shallow average reservoir depth of less than 4,500 ft (<1,370 m), low average API gravity of less than 29°, and tight grouping greater than one standard deviation below the API depth trend line. The Cap Rock and Paluxy Fault Line plays both contain a small number of reservoirs, and the individual reservoirs are in an advanced stage of

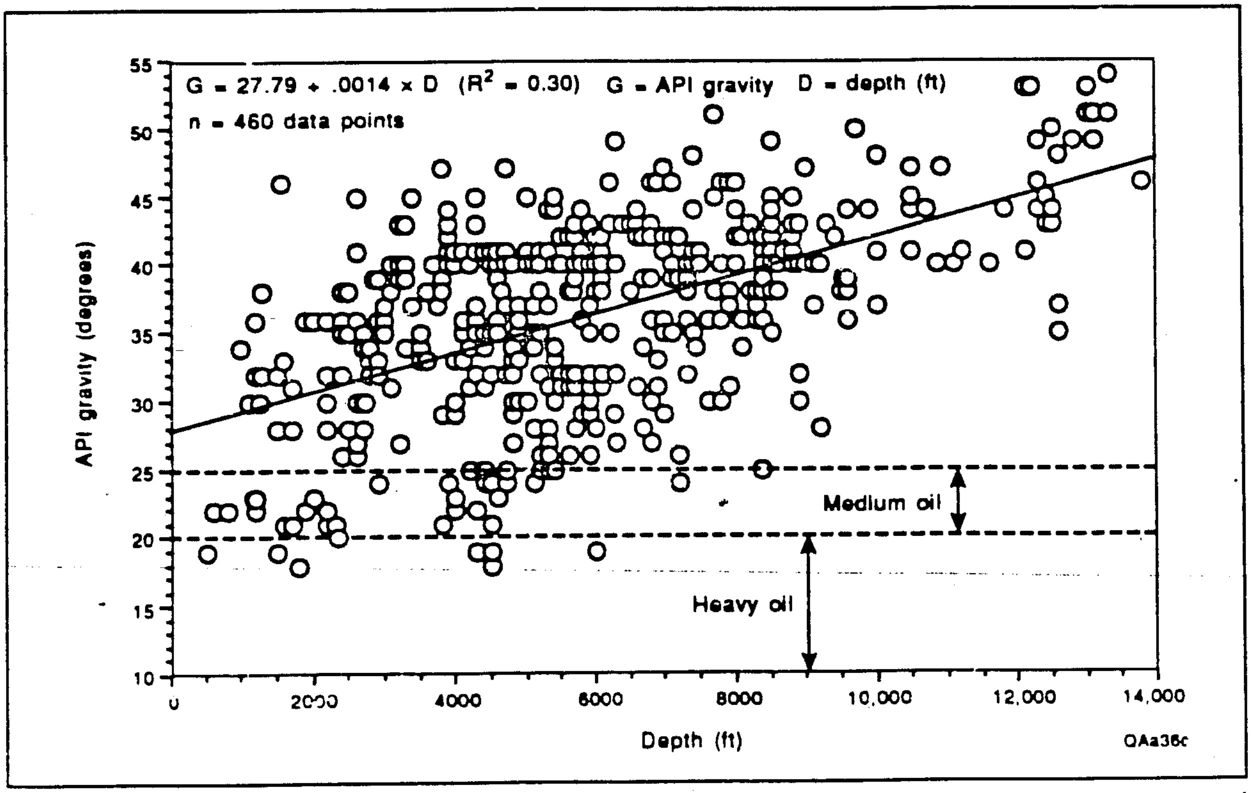


Figure 16. Graph of API gravity versus depth for all large oil reservoirs in Texas. Graph generated from data in Tyler and others (1991).

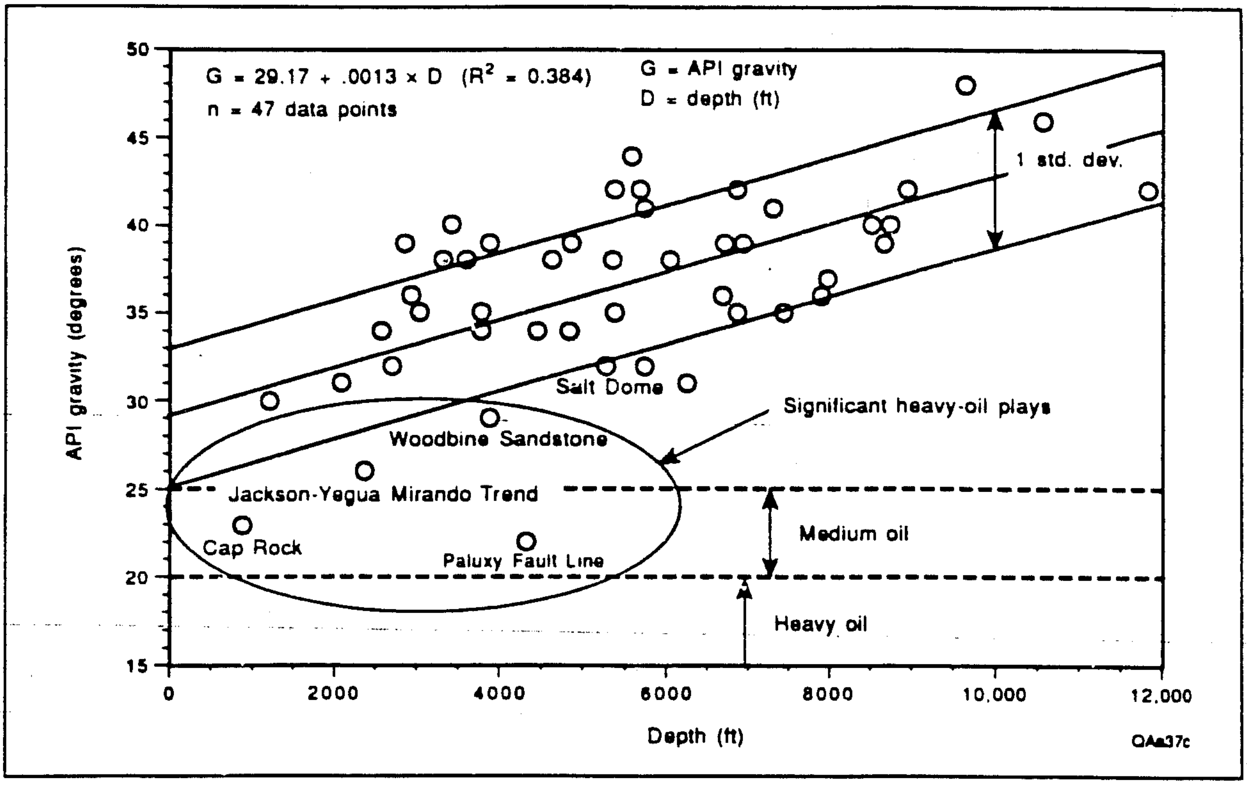


Figure 17. Graph of average API gravity versus average depth for all oil plays in Texas. Graph generated from data in Galloway and others (1983) and Tyler and others (1991).

depletion. The Woodbine Fluvial/Deltaic/Strandplain Sandstone play contains a single supergiant medium- to heavy-oil reservoir, Hawkins Woodbine. Oil gravity of individual wells within the Woodbine reservoir varies widely. Hawkins field produces from a faulted (individual faults are typically nonsealing) domal trap over a salt anticline in the East Texas Basin (Galloway and others, 1983). The base of the reservoirs is sealed by a 50- to 100-ft-thick (15- to 30-m) asphalt layer containing less than 12° gravity hydrocarbons (King and Lee, 1976). The Piercement Salt Dome and Jackson-Yegua Barrier/Strandplain Sandstone plays contain both heavy- and medium-gravity reservoirs. The greater average depth of the Piercement Salt Dome play results in the slightly higher average API gravity of this play. Medium gravity is characteristic of the shallow reservoirs in the Piercement Salt Domes. The Jackson-Yegua Barrier/Strandplain Sandstone play has the highest percentage of heavy- and medium-gravity reservoirs of the large plays that include more than three reservoirs. The following section will discuss in greater detail the distribution of medium- and heavy-oil reservoirs in the Jackson-Yegua Barrier/Strandplain Sandstone play in South Texas.

Medium- and Heavy-Oil Reservoirs in Jackson-Yegua Barrier/Strandplain Sandstones

In the South Texas area (Bee, Duval, Jim Hogg, McMullen, Starr, Webb, and Zapata Counties), large oil reservoirs in the Jackson Group compose the Jackson-Yegua Barrier/Strandplain Sandstone play (Galloway and others, 1983), whereas both large and small Jackson-Yegua fields constitute the Mirando Trend (West, 1963) (fig. 15). For convenience, in this report the term *large reservoirs* refers only to reservoirs in the Jackson-Yegua Barrier/Strandplain Sandstone play, all of which have exceeded 10 MMbbl (>1.6 × 10^6 m^3) cumulative production, and the term *Mirando Trend* refers to both the play and the continuum of fields in the trend.

Sandstone-rich sequences in the Jackson Group in South Texas are informally referred to as the Mirando, Loma Novia, Government Wells, and Cole sandstones. Although the Mirando Trend derived its name from

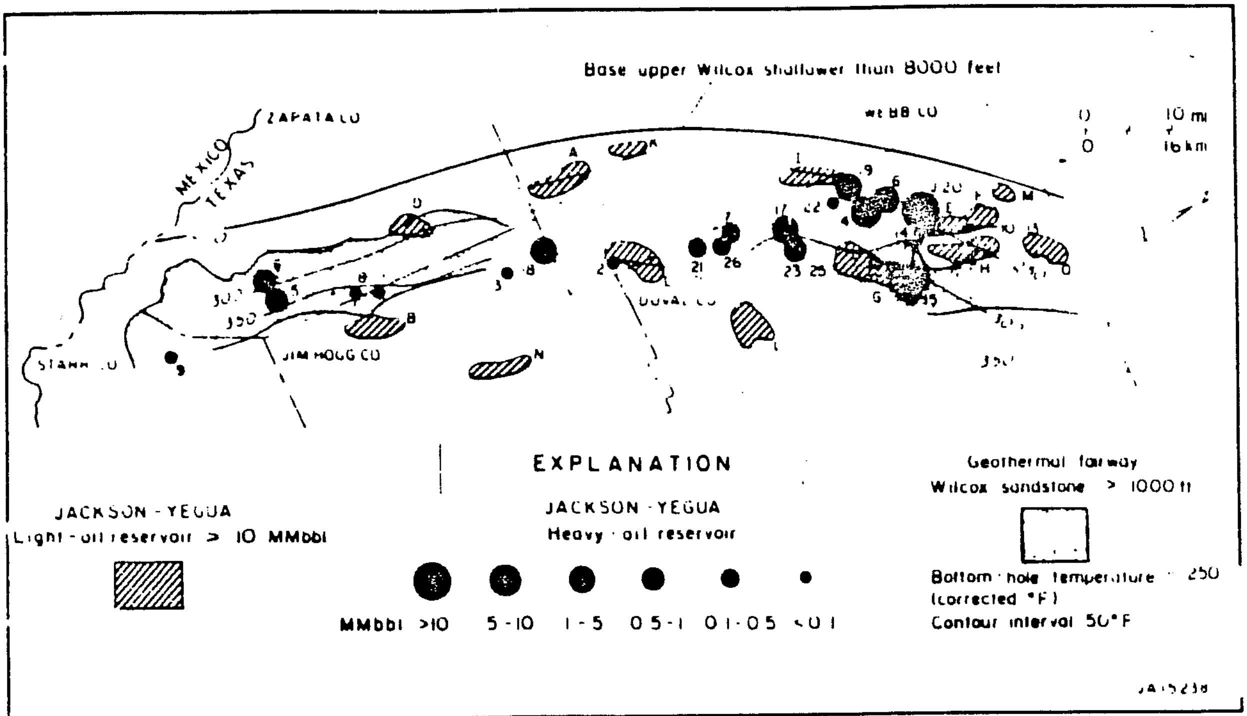


Figure 18. Map showing geopressured-geothermal corridor of the deep upper Wilcox in South Texas (Gregory and others, 1980; Hamlin and others, 1989), the location of two geothermal fairways (stippled) associated with net sandstone in the upper Wilcox thicker than 1,000 ft (300 m), the distribution of large oil reservoirs (Ewing, 1983), and the location of heavy-oil reservoirs within the geopressured-geothermal corridor. Heavy-oil reservoirs are represented by solid circles whose size is proportional to the size of the reservoir. Letters associated with each large oil reservoir refer to reservoir names listed in appendix 1. Numbers associated with each heavy-oil reservoir refer to reservoir names listed in appendix 1. Updip of the corridor, the base of the upper Wilcox is shallower than 8,000 ft (<2,450 m). The corridor includes the area downdip of the 250°F (121°C) isotherm in the upper Wilcox.

reservoirs in the Mirando sandstone, it includes reservoirs in all of the informally named Jackson Group sandstones, as well as in Yegua sandstones such as the Pettus sandstone. The Government Wells and Cole sandstones lie within the upper Jackson, whereas the Loma Novia and Mirando sandstones are in the lower Jackson.

Two classes of oil reservoirs were analyzed in the Jackson Group in South Texas: (1) all large oil reservoirs (16) with cumulative production greater than 10 MMbbl ($>1.6 \times 10^6$ m^3) that compose the Jackson-Yegua Barrier/Strandplain Sandstone play (Galloway and others, 1983) and (2) all heavy-oil reservoirs (26) with API gravity less than or equal to 20° that are colocated within the South Texas geothermal corridor (fig. 18; tables 5 and 6). In this report, the South Texas Wilcox geothermal corridor is defined by the area where the base of the upper Wilcox is deeper than 8,000 ft (2,438 m) (fig. 18). The corridor is downdip of the 250°F (121°C) temperature contour in the upper Wilcox and is associated with thick net sandstones in the deep upper Wilcox (Gregory and others, 1980; Hamlin and others, 1989) in the five-county area of Duval, Jim Hogg, Starr, Webb, and Zapata Counties. Well control and locations of cross sections are shown in figure 19.

Large Reservoirs

Our survey of large oil reservoirs within the Jackson-Yegua Barrier/Strandplain Sandstone play (Galloway and others, 1983; Tyler and others, 1991) includes those that have produced heavy- (≤20°), medium- (>20° to 25°), and light- (>25°) gravity oil (table 5). The large reservoirs have oil with an average API gravity of 25°. One additional field and reservoir—Lundell (Cole)—was added to the play compilation because it achieved cumulative production greater than 10 MMbbl ($>1.6 \times 10^6$ m^3). Not all of the large oil reservoirs lie within the geothermal

Table 5. Characteristics of large oil reservoirs.

RRC district	Field and reservoir	Discovery date	Lithology	Trap*	Drive†	Depth (ft)	Oil column (ft)	Porosity (%)	Permeability Average (md)	Permeability Log range	Water saturation	API gravity	Initial gas-oil ratio
4	Aviators, Mirando	1922	Sandstone	UPP	SG + WD	1,700	51	32	357	1–3	37	21	—
4	Colorado, Cockfield	1936	Sandstone	UPP	SG	2,600	300	28	800	2–3	25	45	287
4	Conoco Driscoll	1937	Sandstone	NPP	GCE	2,800	54	31	458	—	32	33	139
4	Escobas, Mirando	1928	Sandstone	NPP	SG	1,200	70	30	500	1–3	40	23	—
4	Govt. Wells N	1928	Sandstone	UPP	SG + WD	2,200	60	32	800	2–3	30	21	800
4	Govt. Wells S	1928	Sandstone	UPP	SG	2,300	89	30	600	2–3	35	21	880
4	Hoffman, Dougherty	1947	Sandstone	NPP	SG	2,000	250	34	757	—	40	23	85
4	Loma Novia, Loma Novia	1935	Sandstone	UPP	SG	2,600	240	26	800	1–3	25	26	40
4	Lopez, First Mirando	1935	Sandstone	UPP	Combined	7,200	70	35	250	1–3	40	22	—
4	Lundell	1937	Sandstone	UPP	SG	1,528	10	—	—	—	—	19	—
4	Mirando City, Mirando	1921	Sandstone	UPP	Combined	1,600	35	33	1,600	2–3	40	21	125
4	O'Hern, Pettus	1930	Sandstone	NPP	SG	2,700	200	28	286	1–3	20	28	—
4	Piedre Lumbre	1935	Sandstone	NPP	WD + SG	1,900	65	30	300	1–3	30	22	—
4	Prado Middle, Loma Novia	1956	Sandstone	UPP	SG + GCE	3,700	65	32	850	1–4	26	40	600
4	Seven Sisters	1935	Sandstone	NPP	SG + WD	2,330	75	28	225	1–2	55	20	—
	15 fields, 15 reservoirs												
	Mean					2,220	109	31	613		34	26	370

Table 5 (cont.)

RRC district	Field and reservoir	Initial pressure	Temperature (°F)	Production technology‡	Unitization date	Well spacing (acres)	Residual oil saturation (%)	Oil in place (MMbbl)	Cumulative production (MMbbl)	Ultimate recovery (MMbbl)	Recovery efficiency (%)
4	Aviators, Mirando	700	107	WF	1966	10	25	37	10.1	10.3	28
4	Colorado, Cockfield	1,125	145	WF	—	10–40	31	52	21.7	21.8	42
4	Conoco Driscoll	1,290	153	PMG	1937	20	9	69	20.0	23.7	34
4	Escobas, Mirando	575	100	WF, T	—	10	30	28	12.8	12.9	46
4	Govt. Wells N	875	114	WF, P, T	—	10	36	150	77.3	78.0	52
4	Govt. Wells S	850	—	PMG, WF	—	10	20	40	16.6	18.0	45
4	Hoffman, Dougherty	795	131	WF, P	—	16	18	55	20.5	21.0	38
4	Loma Novia, Loma Novia	1,003	114	WF, PMG	—	10	35	176	47.7	48.0	27
4	Lopez, First Mirando	780	111	PMG, WF, T	1955	10	25	75	30.4	33.0	44
4	Lundell	700	—	WF	—	—	—	—	10.4	—	—
4	Mirando City, Mirando	665	—	WF, T	—	—	25	46	12.1	12.1	26
4	O'Hern, Pettus	990	136	PMG, WF, T	1957	10	20	83	22.2	30.0	36
4	Piedre Lumbre	820	100	PMG, WF, LPG	—	10	25	95	20.7	22.0	23
4	Prado Middle, Loma Novia	1,407	109	PMG, WF	1957	10	30	38	10.4	23.7	62
4	Seven Sisters	1,150	132	PMG, WF	—	10	15	142	35.0	56.0	39
	15 fields, 15 reservoirs										
	Mean	915	121				25				
	Sum							1,086	367.9	440.5	39

*Types of trap are the following: NPP = porosity pinch-out across a nose (dome, terrace); SSF = simple sealing fault; and UPP = updip porosity pinch-out.
†Types of drive are the following: Combined = two or more types of drive; GCE = gas-cap expansion; SG = solution-gas drive (depletion, fluid expansion, etc.); and WD = water drive.
‡Types of production technology are LPG = liquified petroleum gas flood; P = polymer flood; PMG = pressure maintenance by gas injection; T = thermal recovery project; and WF = waterflood.
Dashes indicate information is not available.

Table 6. Characteristics of heavy-oil reservoirs.

RRC district	Field and reservoir	Discovery date	Lithology	Trap*	Drive†	Depth (ft)	Oil column (ft)	Porosity (%)	Permeability: Average (md)	Permeability: Log range	Water saturation	API gravity	Initial pressure
4	Alworth, Cole sand	1965	Sandstone	NPP	WD	1,040	6	29	511	—	31	19	191
4	Bruni S	1944	Sandstone	UPP	—	1,804	—	31	600	—	—	19	—
4	Bruja Vieja, Cole sand	1950	Sandstone	UPP	—	1,755	—	—	—	—	—	18	—
4	Cedro Hill	1938	Sandstone	UPP	SG + WD	1,440	12	31	700	—	42	19	400
4	Charco Redondo	1913	Sandstone	UPP	SG	339	14	33	1,659	1–2	25	17	30
4	Colema	1936	Sandstone	UPP	SG + WD	1,500	20	32	650	—	[illegible]	19	600
4	Dinn	1949	Sandstone	UPP	WD	1,805	5	—	—	—	—	19	—
4	Edlasater W, Cole 950	1968	Sandstone	UPP	—	950	—	—	—	—	—	20	—
4	El Puerto N, O'Hern	1965	Sandstone	NPP	—	760	—	—	—	—	—	20	—
4	Govt. Wells N, 900 sand	1948	Sandstone	UPP	—	918	—	—	—	—	—	20	—
4	Govt. Wells N, 1000 sand	1950	Sandstone	UPP	—	1,062	—	—	—	—	—	19	—
4	Govt. Wells N, 1150	1978	Sandstone	UPP	—	1,167	—	—	—	—	—	20	—
4	Govt. Wells N, 1550	1949	Sandstone	UPP	—	1,547	—	—	—	—	—	20	—
4	Govt. Wells S, Hockley 1900	1965	Sandstone	UPP	—	1,919	—	—	—	—	—	19	—
4	Hoffman E	1950	Sandstone	UPP	SG	2,038	20	—	—	—	—	20	—
4	Joe Moss, 500 sand	1952	Sandstone	UPP	—	500	—	—	—	—	—	20	—
4	Kohler NE, Mirando No. 2	1980	Sandstone	SSF	SG	2,633	—	—	—	—	—	19	—
4	Las Animas–Lefevre	1937	Sandstone	UPP	SG	1,793	20	31	800	—	35	19	620
4	Lopez N, (Lopez)	1951	Sandstone	UPP	SG	2,064	10	35	428	—	33	20	960
4	Lundell	1937	Sandstone	UPP	SG	1,528	10	—	—	—	—	19	700
4	Orlee	1949	Sandstone	NPP	WD	1,697	10	25	200	—	35	20	765
4	Peters N, first Cole sand	1959	Sandstone	SSF	—	1,746	—	—	—	—	—	20	—
4	Rancho Solo	1937	Sandstone	SSF	—	1,849	—	—	—	—	—	19	—
4	Rancho Solo, second Cole	1959	Sandstone	UPP	—	1,840	—	31	—	—	—	20	—
4	Rancho Solo, extension	1939	Sandstone	UPP	—	1,836	—	—	—	—	—	19	—
4	Richardson	1944	Sandstone	UPP	—	1,784	—	—	—	—	—	18	—
	21 fields, 26 reservoirs Mean					1,512	12.7	31	694		34	19	533

*Types of trap are the following: NPP = porosity pinch-out across a nose (dome, terrace); SSF = simple sealing fault; and UPP = updip porosity pinch-out.
†Types of drive are the following: SG = solution-gas drive (depletion, fluid expansion, etc.) and WD = water drive.
‡Types of production technology are the following: T = thermal recovery project and WF = waterflood.
Dashes indicate information is not available.

Table 6 (cont.)

RRC district	Field and reservoir	Production technology‡	Well spacing (acres)	Residual oil saturation (%)	Cumulative production (MMbbl)	Producing sandstone
4	Alworth, Cole sand	WF	63	—	.078	Cole
4	Bruni S	—	—	—	.001	Cole
4	Bruja Vieja, Cole sand	—	—	—	.001	Cole
4	Cedro Hill	WF	—	13.65	6.569	Cole
4	Charco Redondo	T	—	7.7	.659	Cole
4	Colema	WF	—	—	3.868	Cole
4	Dinn	—	—	—	.319	Cole
4	Edlasater W, Cole 950	—	—	—	.013	Cole
4	El Puerto N, O'Hern	—	—	—	.001	Fourth Mirando
4	Govt. Wells N, 900 sand	—	—	—	.315	Cole
4	Govt. Wells N, 1000 sand	—	—	—	.080	Cole
4	Govt. Wells N, 1150	—	—	—	.023	Cole
4	Govt. Wells N, 1550	—	—	—	.030	Cole
4	Govt. Wells S, Hockley 1900	—	—	—	.030	Taracahuas
4	Hoffman E	—	—	—	1.367	Taracahuas
4	Joe Moss, 500 sand	—	—	—	.557	Second Mirando
4	Kohler NE, Mirando No. 2	—	—	—	1.217	Cole
4	Las Animas–Lefevre	—	—	—	3.402	Cole
4	Lopez N (Lopez)	WF	—	3.600	2.225	Cole
4	Lundell	WF	—	—	10.358	Cole
4	Orlee	WF	—	—	.266	First Cole
4	Peters N, first Cole sand	—	—	—	.042	Cole
4	Rancho Solo	—	—	—	.465	First Cole
4	Rancho Solo, second Cole	—	—	—	.030	Second Cole
4	Rancho Solo, extension	—	—	—	.520	Cole
4	Richardson	—	—	—	.147	Cole
	21 fields, 26 reservoirs					
	Sum				32.92	

*Types of trap are the following: NPP = porosity pinch-out across a nose (dome, terrace); SSF = simple sealing fault; and UPP = updip porosity pinch-out.
†Types of drive are the following: SG = solution-gas drive (depletion, fluid expansion, etc.) and WD = water drive.
‡Types of production technology are the following: T = thermal recovery project and WF = waterflood.
Dashes indicate information is not available.

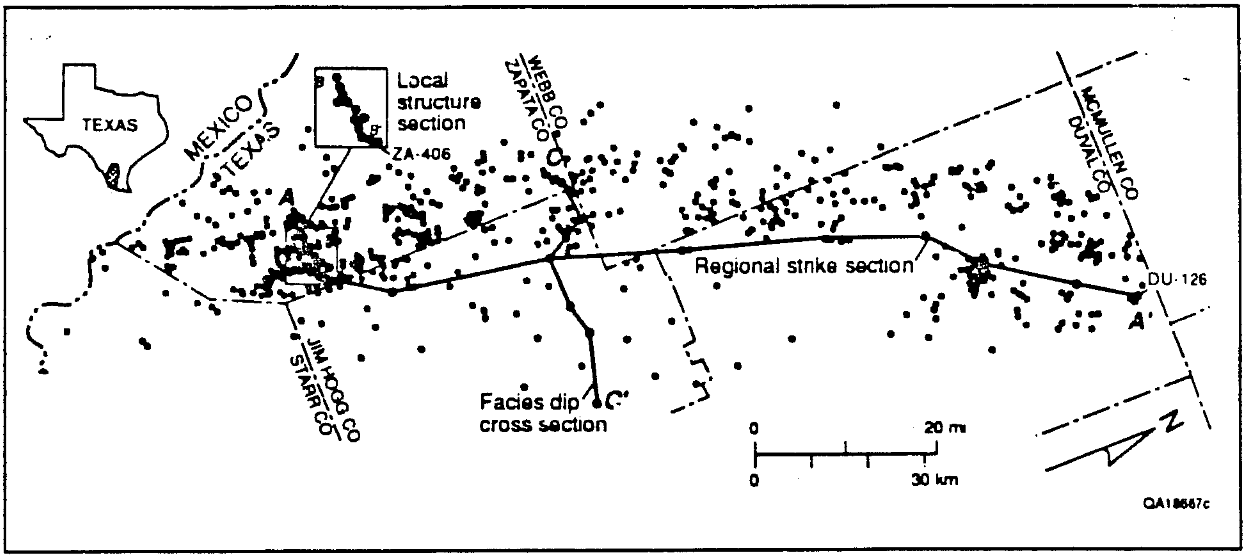


Figure 19. Map locating well control and cross sections. Names of wells on cross sections are listed in appendix 2.

corridor. Original oil in place of the large reservoirs in the Jackson-Yegua Barrier/Strandplain Sandstone play alone is 1.1 Bbbl (1.7×10^8 m^3) (Galloway and others, 1983), and cumulative production is 448 MMbbl (7.1×10^7 m^3) (Tyler and others, 1991). Recovery efficiency using primary and secondary recovery for the large reservoirs is a relatively low 37 percent (Galloway and others, 1983). The large reservoirs in the trend (Government Wells—cumulative production 80.0 MMbbl [1.3×10^7 m^3] through 1990 and Loma Novia—cumulative production 48.6 MMbbl [7.7×10^6 m^3] through 1990) produce medium-gravity oil. Two of the large reservoirs, Lundell and Seven Sisters, produce heavy oil; eight of the large reservoirs produce medium oil. Heavy-oil reservoirs represent 15 percent and medium-oil reservoirs 53 percent of the cumulative production of the large reservoirs in the Mirando Trend in the five-county area. Oil gravity may be quite variable within a given field or reservoir. For example, in the largest field in the Mirando Trend, Government Wells North, 20 separate reservoirs produce from Jackson and Yegua sandstones. Oil gravity ranges from 19° to 35.1° (mean gravity = 24.64°; standard deviation = 5.13°) over a depth range of 918 to 3,264 ft (280 to 995 m), a mean depth of 1,855 ft (565 m), and a standard deviation of 646 ft (197 m).

Heavy-Oil Reservoirs

In the South Texas geothermal corridor, 21 heavy-oil fields (26 reservoirs) have a minimum cumulative production of 1,000 bbl (159 m^3) per reservoir (table 6). This corridor covers a small area of the Mirando Trend, and thus many heavy-oil reservoirs lie outside the geothermal corridor boundary. The heavy-oil reservoirs compose a resource target with original oil in place of 110 to 330 MMbbl (1.7×10^7 to 5.2×10^7 m^3) over the South Texas geothermal corridor (fig. 15). Recovery efficiency of the heavy-oil reservoirs is estimated at 10 to 30 percent (Charles Kimmell, Fanion Production Company, personal communication, 1990). Total cumulative production from the heavy-oil fields in the South Texas geothermal corridor is 32.9 MMbbl (5.2×10^6 m^3). Seven Sisters (first Cole), the largest heavy-oil field, had a cumulative production of 56.0 MMbbl (8.9×10^6 m^3) through 1988; however, it is located just updip of the geothermal corridor. Lundell, the largest heavy-oil reservoir within the geothermal corridor, had a cumulative production of 10.4 MMbbl (1.65×10^6 m^3) through 1988.

API Gravity and Depth

A plot of API gravity versus depth illustrates an important correlation of API gravity with depth of the large and heavy-oil reservoirs (fig. 20) of the Mirando Trend. The large oil reservoirs show two trends of API gravity with depth: (1) a shallow trend of relatively consistent API gravity (average API gravity = 21°) over a depth range of 1,000 to 2,500 ft (305 to 762 m) and (2) a deep trend of increasing API gravity with increasing

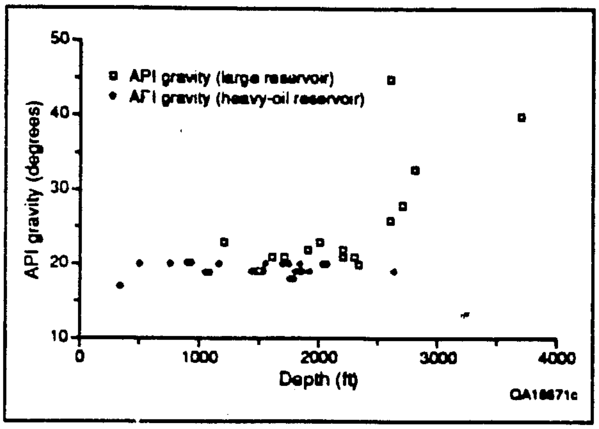


Figure 20. Plot of API gravity as a function of depth for two types of Jackson Group reservoirs in South Texas: large reservoirs and heavy-oil reservoirs. Large reservoirs tend to be deeper and have a greater API gravity value (less viscous) than heavy-oil reservoirs.

depth over a depth range of 2,500 to 4,000 ft (762 to 1,219 m). The heavy-oil reservoirs show a relatively constant gravity (average API gravity = 19.3°) over a depth range of 200 to 2,500 ft (61 to 762 m). Heavy-oil reservoirs are much shallower than the large reservoirs (mean depth of 1,512 ft [461 m] for heavy reservoirs versus 2,273 ft [693 m] for large reservoirs). The overall trend of API gravity for both populations of reservoirs illustrates relatively constant gravity (average API gravity = 20°) for reservoirs at a depth of 200 to 2,500 ft (61 to 762 m). The gravity trend then increases linearly for reservoirs at greater depths.

The rapid increase in API gravity at depths greater than 2,500 ft (>762 m) indicates API gravity is controlled by depth-related processes. Two possibly interrelated processes may be responsible for this increase: (1) a depth-related increase in temperature, which limits activity of oil-degrading bacteria at about 2,500 ft (~762 m) and (2) fresh-water invasion, which is limited to the section shallower than 2,500 ft (<762 m). The consistently low API gravity for the shallow reservoirs is interpreted as resulting from water washing and bacterial degradation that was particularly active above a depth of 2,500 ft (>762 m) (Tissot and Welte, 1984). In the South Texas area, the corrected subsurface temperature would be 119°F (48°C) at 2,500 ft (762 m) (fig. 6). Fresh-water invasion in Jackson Group sandstones is indicated by electric logs that show reversal (positive deflection) of the SP curve to a depth of at least 2,000 ft (610 m). The processes that result in formation of low API gravity crude oils include biodegradation, water washing, loss of volatiles, and oxidation (Philippi, 1977; Tissot and Welte, 1984). Deeper than 2,500 ft (>762 m), the API gravity increases with depth as a function of increasing temperature above 119°F (>48°C), absence of meteoric water, and less biodegradation.

The API gravity of oil in South Texas Mirando Trend reservoirs also reveals a stratigraphic and geographic segregation among the various Jackson Group sand bodies (fig. 21). The Mirando Trend includes reservoirs within the upper Jackson Group Cole and Government Wells sandstones and the lower Jackson Group Loma Novia and Mirando sandstones, as well as within the Yegua Formation Pettus sandstone. Seventy-nine percent of the oil in the largest reservoirs is in the Government Wells and Mirando sands, and the largest reservoirs contain predominantly medium-gravity oil. In contrast, 84 percent of the heavy oil is in Cole sands. The Cole sands contain no medium-oil reservoirs that have a cumulative production greater than 10 MMbbl (>1.6 × 10^6 m^3). The shallow Cole sands contain many small heavy-oil reservoirs, whereas the medium-oil reservoirs in the Mirando and Government Wells sands are much larger.

Discussion

The greatest concentration of medium- and heavy-oil reservoirs lies along the Texas Gulf Coast in the (1) Jackson-Yegua Barrier/Strandplain Sandstone, (2) Cap Rock, and (3) Piercement Salt Dome plays. Many medium-oil reservoirs also lie in the Frio Barrier/Strandplain Sandstone play along the central Texas Gulf Coast. The East Texas Basin also contains a few large medium- and heavy-oil reservoirs in two plays, the Paluxy Fault Line and the Woodbine Fluvial/Deltaic/Strandplain plays. The Gulf Coast region in Texas is most favorable for juxtaposition of oil plays containing large medium- to heavy-oil reservoirs and geothermal corridors. The Jackson-Yegua Barrier/Strandplain Sandstone play (Mirando Trend) is the most favorable play for thermal development of medium- to heavy-oil reservoirs because of the abundance, the large size, and the shallow depth of reservoirs.

The general trend of decreasing API gravity (increasing viscosity) with decreasing depth is attributed to degradation of oil quality through oxidization by contact with meteoric waters and biodegradation by aerobic bacteria (Tissot and Welte, 1984; North, 1985). According to Tissot and Welte (1984), most heavy oils originate from normal, light crude oils that have been subsequently degraded in the reservoir by one or more processes, including biodegradation, water washing, loss of volatiles, and inorganic oxidation. As a result, the percentage of light fractions in the crude oil decreases and the

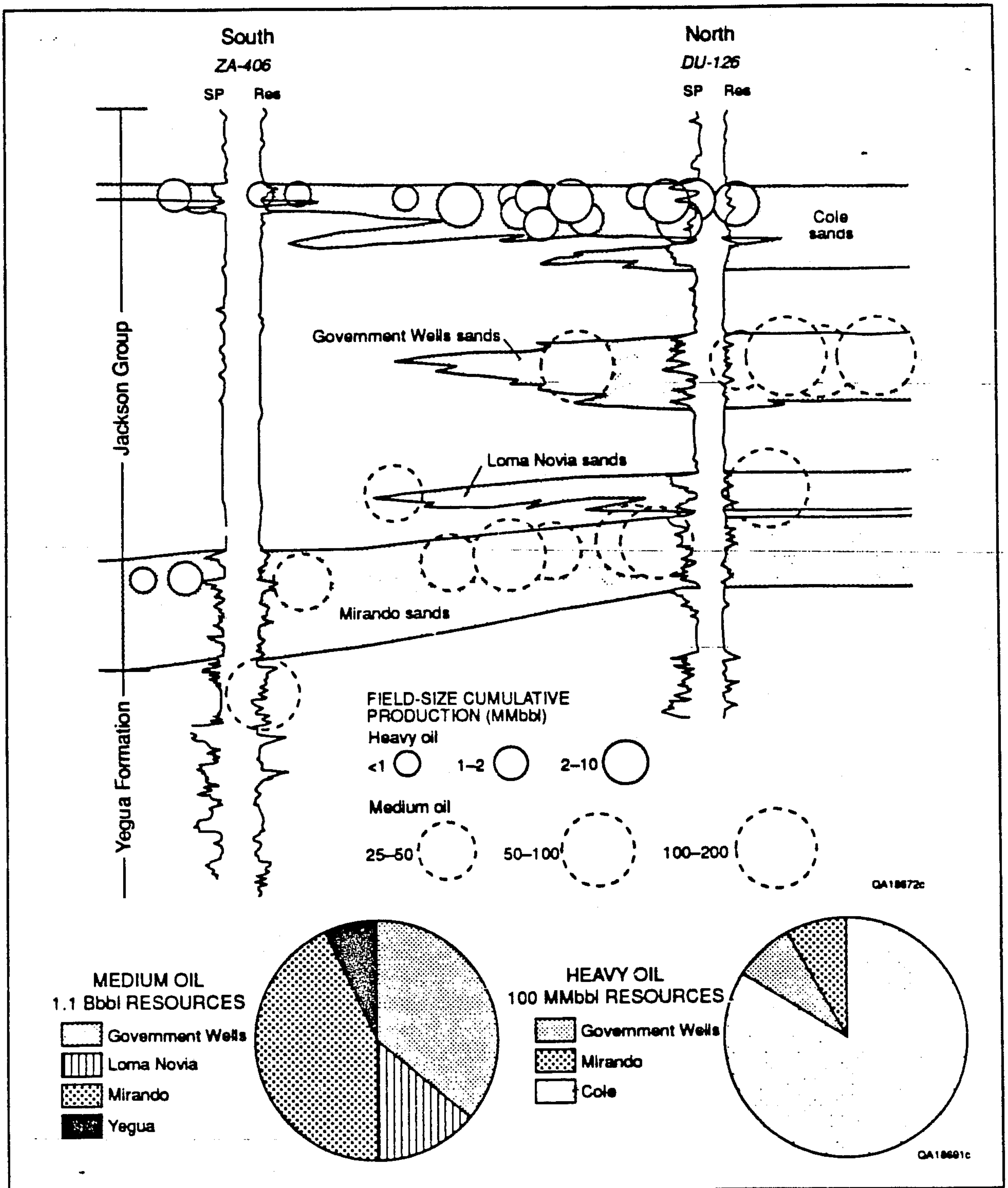


Figure 21. Cross section A–A' along strike from Zapata County (south) to Duval County (north) illustrating stratigraphic and lateral distribution of heavy-oil reservoirs (API ≤20°) and large reservoirs in the Jackson Group (from Galloway and others, 1983). Pie diagrams show segregation of reservoirs within stratigraphic horizons. Heavy-oil reservoirs are concentrated in Cole sands, whereas large reservoirs are concentrated in Government Wells, Loma Novia, and Mirando sands. Wells are located at southern and northern ends of regional strike section (figure 19). Well names are listed in appendix 2.

percentage of more resistant heavier fractions, including the asphaltenes, increases. The extent of degradation is associated with depth, proximity to meteoric waters, and salinity of formation waters. The medium- and heavy-oil reservoirs in Texas are excellent examples of degradation through these processes. In contrast to the dominant trend of decreasing API gravity with decreasing depth in Texas, some basins, such as Greater Oficina area in Venezuela and the Baku region of the Caspian Sea, exhibit the opposite trend of decreasing API gravities with increasing depth as a result of density stratification and increases in water salinity with depth (North, 1985).

Although medium- and heavy-oil reservoirs constitute 10 percent of the large oil reservoirs in Texas, their cumulative production represents only 8.4 percent of the production from the large oil reservoirs. The 1.6 percent difference is a result of the lower average productivity of the medium- and heavy-oil reservoirs and is equivalent to a difference of 629 MMbbl (1.0×10^8 m^3) (or 1.6 percent × total cumulative production of large reservoirs in Texas) in production between light- and medium- to heavy-oil reservoirs. This is one measure of the potential size of the resource target that is available for geothermally enhanced recovery.

Tyler and others (1984) used the plays delineated by Galloway and others (1983) to evaluate targets for additional recovery of oil in Texas. For the Jackson-Yegua Barrier/Strandplain Sandstone play alone, they calculated 249 MMbbl (4.0×10^7 m^3) of potentially recoverable target oil. Tyler and others (1984) based their calculation on 1.13 Bbbl (1.8×10^8 m^3) original oil in place, 62 percent unrecovered oil, 27 percent residual oil saturation, 33 percent water saturation (target oil = [percentage of unrecovered oil–(residual oil saturation/1–water saturation)] × original oil in place).

Jackson Group Sand-Body Geometry, Facies, and Diagenesis

Previous regional studies documented the sheetlike geometry and strike orientation of barrier bar/strandplain sands in the Jackson Group of South Texas (West, 1963; Fisher and others, 1970; Kaiser and others, 1978, 1980) and characterized specific oil fields and reservoirs (Galloway and others, 1983; Hopf, 1986; Schultz, 1986; Hyatt, 1990). Our analysis of Jackson Group sand-body geometry and depositional facies in the five-county study area supports previous interpretations of the dominance of shoreline barrier bar/strandplain facies in South Texas. Although the regional architecture of Jackson Group sandstones in the Mirando Trend is relatively simple, reservoir-scale architecture is complex in terms of sand-body geometries, depositional facies, and diagenesis. These complexities must be understood because they affect the suitability of Jackson Group sandstone reservoirs for a TEOR program.

Sand-Body Geometry

The Jackson Group in South Texas forms a sand-rich belt, 20 to 25 mi (32 to 40 km) wide, bounded by mudstone both updip and downdip (fig. 22). A dip-oriented cross section of the Jackson Group in Zapata County illustrates the typical structural setting and stratigraphic relationships of the Jackson Group across the deep Wilcox geothermal fairway and the association of oil reservoirs with the updip pinch-out of strike-elongate sandstones (fig. 23). The influence of faulting on regional patterns of hydrocarbon entrapment is relatively insignificant. However, small faults do form barriers to lateral migration in individual reservoirs. The gulfward dip of Jackson strata ranges from 125 to 250 ft/mi (1.4° to 2.7°) and has enhanced the gravity segregation and updip migration of hydrocarbons toward updip sandstone pinch-outs.

A strike-oriented cross section from Zapata to Duval Counties illustrates the lateral continuity of sandstones in the Jackson Group of the South Texas study area (fig. 24). To the north in Duval County, the Jackson is sand rich where Loma Novia and Government Wells sandstones are thick. The Mirando and upper Cole sandstones are continuous across the area; however, the Loma Novia, Government Wells, and lower Cole sandstones pinch out to the south. The axis of thickest

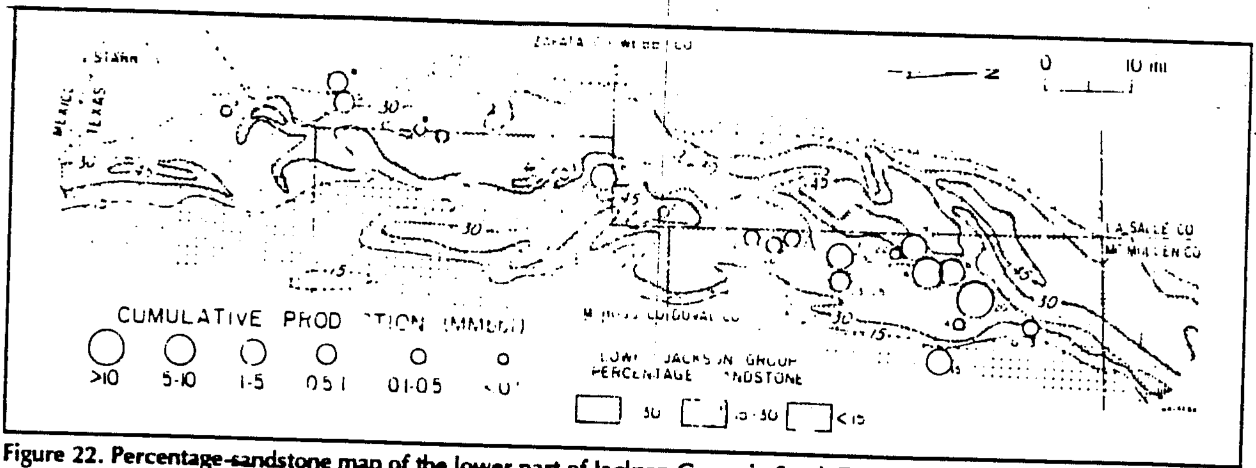


Figure 22. Percentage-sandstone map of the lower part of Jackson Group in South Texas (modified from Kaiser and others, 1980). The percentage of sand for the lower part of the Jackson Group does not control the location of heavy-oil reservoirs, which preferentially occur within the Cole sand in the upper part of the Jackson Group. The percentage-sandstone map emphasizes the distribution of Mirando sands. Numbers associated with each heavy-oil reservoir correspond to reservoir names listed in appendix 1.

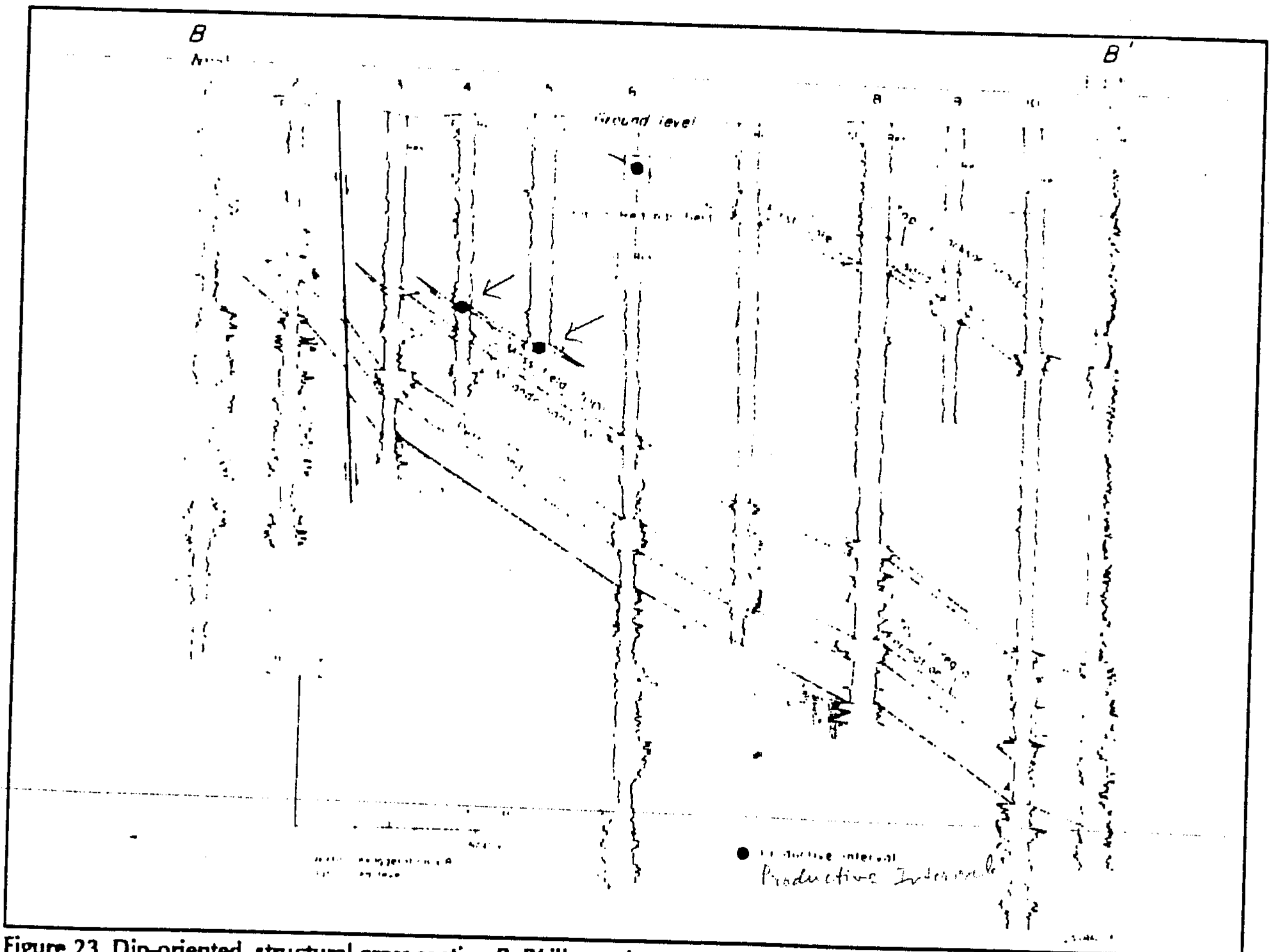


Figure 23. Dip-oriented, structural cross section B–B′ illustrating structure of Jackson Group and updip pinch-out of upper Jackson Group sand bodies. The cross section is labeled as local structure section in figure 19. Well names are listed in appendix 2.

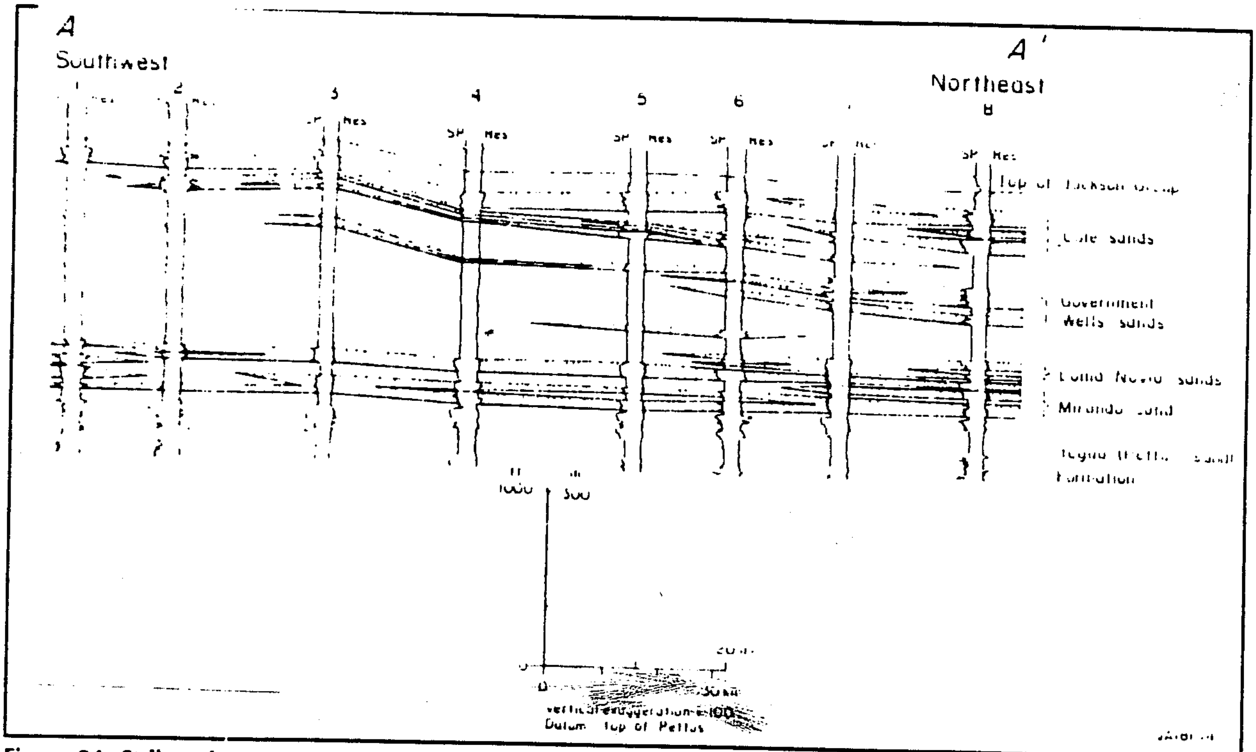


Figure 24. Strike-oriented cross section A–A' illustrating lateral continuity of Jackson Group sand bodies. The cross section is labeled as regional strike section in figure 19. The section demonstrates the decrease in sandstone from northeast to southwest. Datum is top of Yegua (Pettus sand) Formation. Well names are listed in appendix 2.

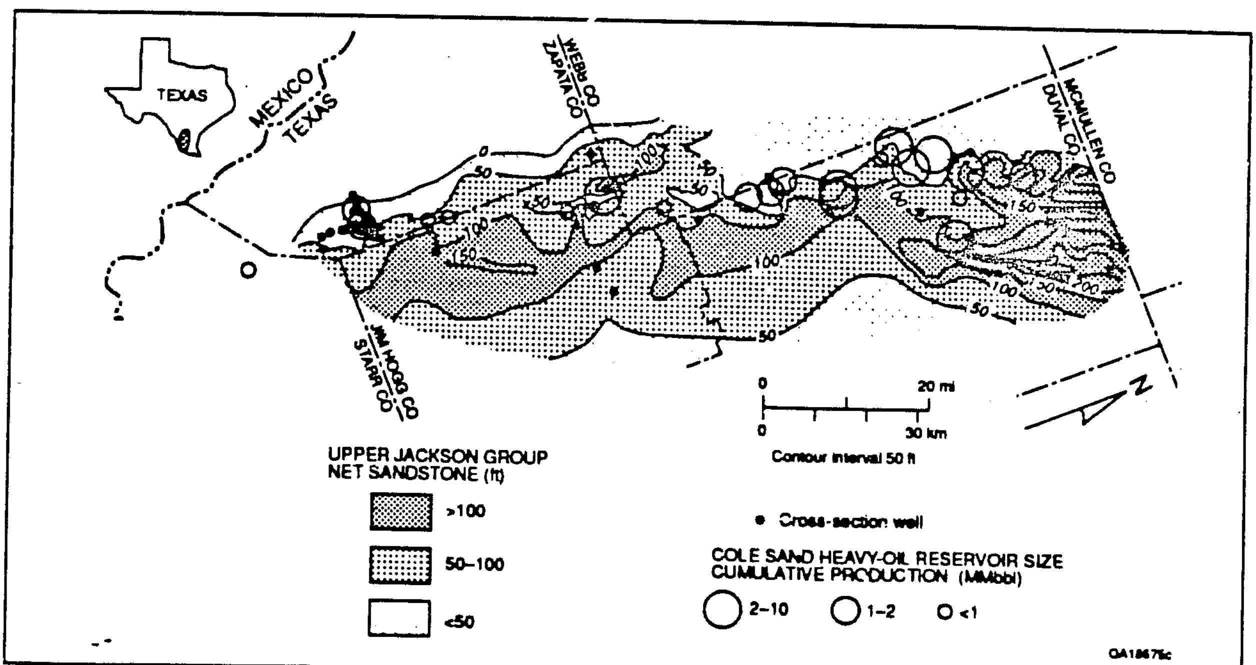


Figure 25. Map of net sandstone thickness of upper Jackson Group including the Cole and Government Wells sands. Net sandstone is thickest in northern Duval County. The strike-parallel orientation of the axis of thick net sandstone supports the interpretation that upper Jackson Group sandstones accumulated principally in barrier/strandplain depositional environments similar to environments of deposition of sandstones of the lower Jackson Group. Heavy-oil reservoirs are preferentially located along updip pinch-out of sandstones.

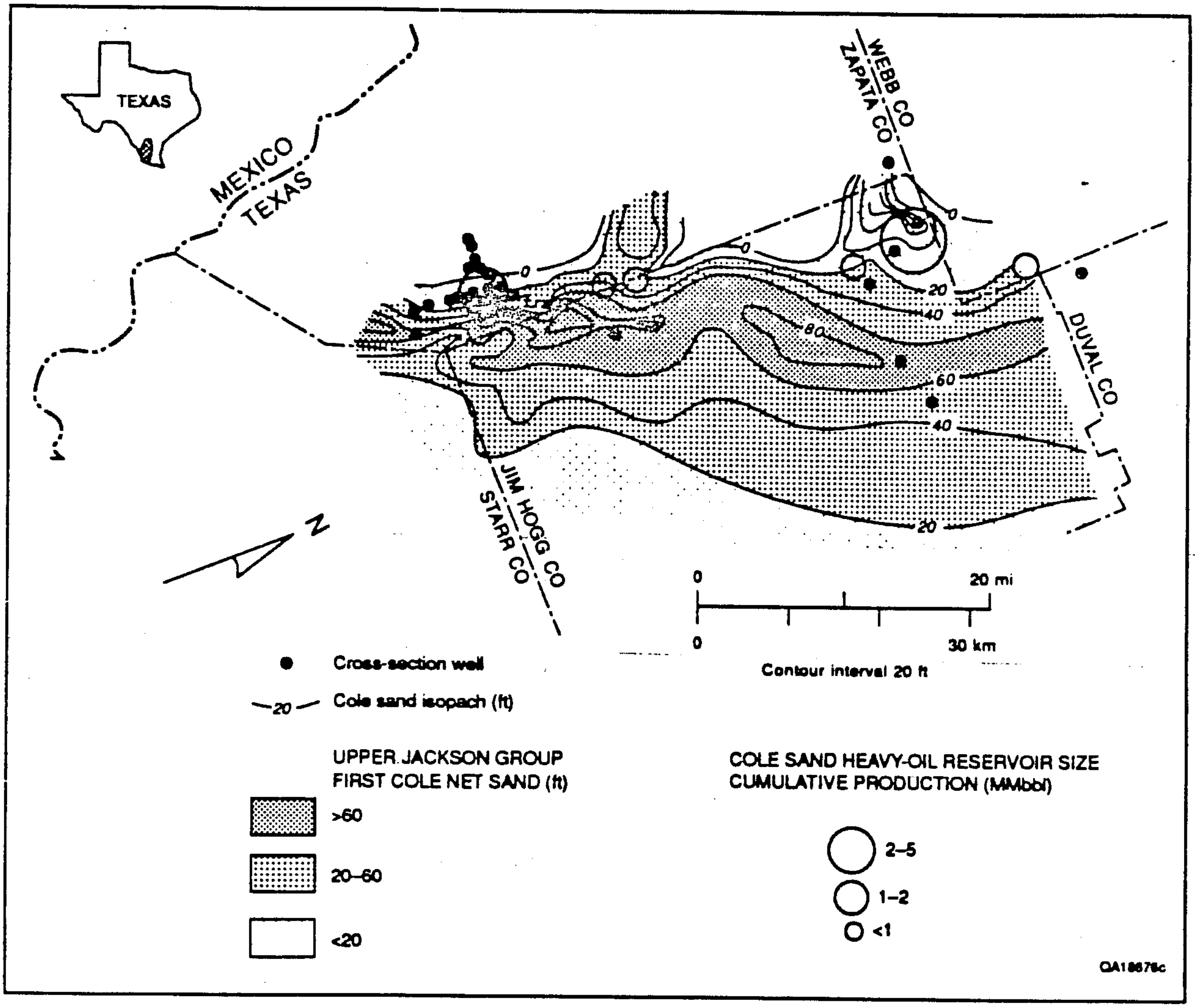


Figure 26. Map of net sandstone thickness of first Cole sand in Jim Hogg and Zapata Counties. Heavy-oil reservoirs are preferentially located along updip pinch-out where sandstone thickness is less than 20 ft.

net sandstone in the upper Jackson has prograded basinward 15 mi (24 km) in the northern part of the study area from the location of the axis for the lower Jackson. However, little seaward progradation of the axis of thick net sandstone occurred in the southern part of the study area, where the Jackson Group is thicker.

A sand-percent map of the lower part of the Jackson Group illustrates the linear strike orientation of the sandstone belt (fig. 22) (Kaiser and others, 1980). A net-sandstone map of the upper Jackson (fig. 25) (including the Cole and Government Wells sandstones) shows a similar strike orientation of sandstone thickness. Sand-body orientation and net sandstone thickness exert a strong control on the location of heavy-oil reservoirs (fig. 25). Heavy-oil reservoirs at Charco Redondo, Ed Lasater, Alworth, Bruja Vieja, Las Animas-Lefevre, and Bruni South fields are located along the updip pinch-out where net sandstone thickness is less than 100 ft (<30 m). At Charco Redondo field the upper Cole sand is 10 to 20 ft (3 to 6 m) thick. Reservoir traps form in updip facies by losing porosity through (1) sand-body pinch-out and (2) increasing percentage of clay in the sand body.

The updip and downdip pinch-out of a single Cole sand body in Jim Hogg and Zapata Counties can also be demonstrated within a vertically restricted stratigraphic section. The thickness of the first Cole sandstone is as much as 100 ft (≤30 m) and its width is approximately 8 to 10 mi (13 to 16 km) (fig. 26).

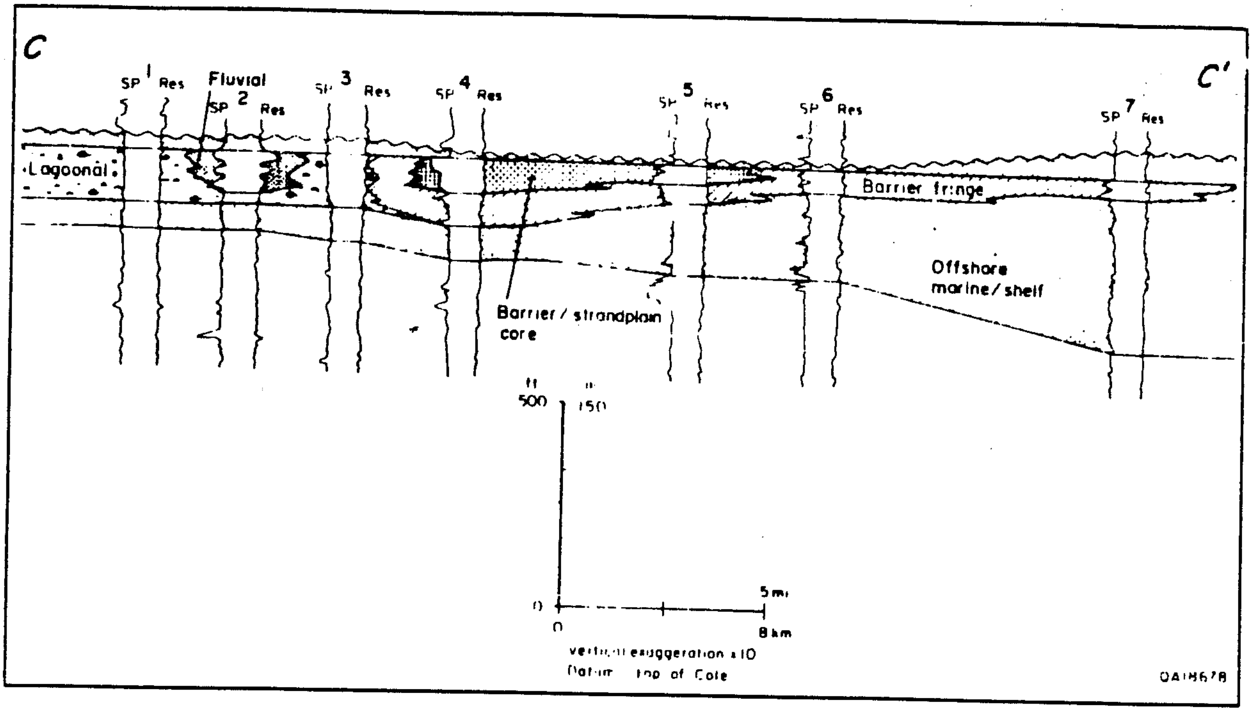


Figure 27. Cross section illustrating C–C' facies relationships in first Cole sand. Cross section is labeled as facies dip cross section in figure 19. Datum is top of first Cole sand. Well names are listed in appendix 2.

Depositional Facies

Reservoir sandstones in the Mirando Trend (and Jackson-Yegua Barrier/Strandplain Sandstone play) are in the barrier bar/strandplain system of the Jackson Group and Yegua Formation. This study focused on the Jackson Group, which contains the most reservoirs. Sand-rich barrier bar/strandplain facies are surrounded by mudstones. Updip to the west, mudstones generally were deposited in lagoonal environments with secondary floodplain environments; downdip to the east, mudstones were dominantly deposited in shelf environments. A dip-oriented facies cross section illustrates lateral relationships between depositional facies and indicates that the sandstones were deposited in a variety of sand-rich depositional environments (fig. 27).

Thickness relationships and log character were used to identify depositional facies (figs. 27 and 28). A depositional facies map (fig. 28) of the first Cole sandstone indicates that heavy-oil reservoirs are located along the updip pinch-out of barrier-fringe facies against lagoonal mudstones. Sand-body thickness is greatest in the barrier-core and strandplain sandstones that are characterized by progradational base and blocky tops. Lagoonal mudstones are present updip of barrier bar/strandplain sandstones. Barrier-core and back-barrier sandy facies rapidly grade updip into sand-poor lagoonal facies. Fluvial facies are isolated within muddy lagoonal facies on the landward updip margin of the sand-rich belt. Within the lagoonal mudstones are isolated, dip-oriented fluvial-deltaic sandstones consisting of thin upward-coarsening packages at the base and multiple upward-fining packages at the top. Fluvial-deltaic sandstones apparently did not prograde across the extensive lagoonal mudstones and breach or feed the barrier bar/strandplain in the study area. Southward thinning of net sandstone and strike-oriented sandstone trends indicate that longshore drift probably supplied sand from the north, where progradation of the shoreline was the most extensive. In a basinward direction, barrier-fringe sandstones thin gradually and are replaced by offshore mudstones and siltstones.

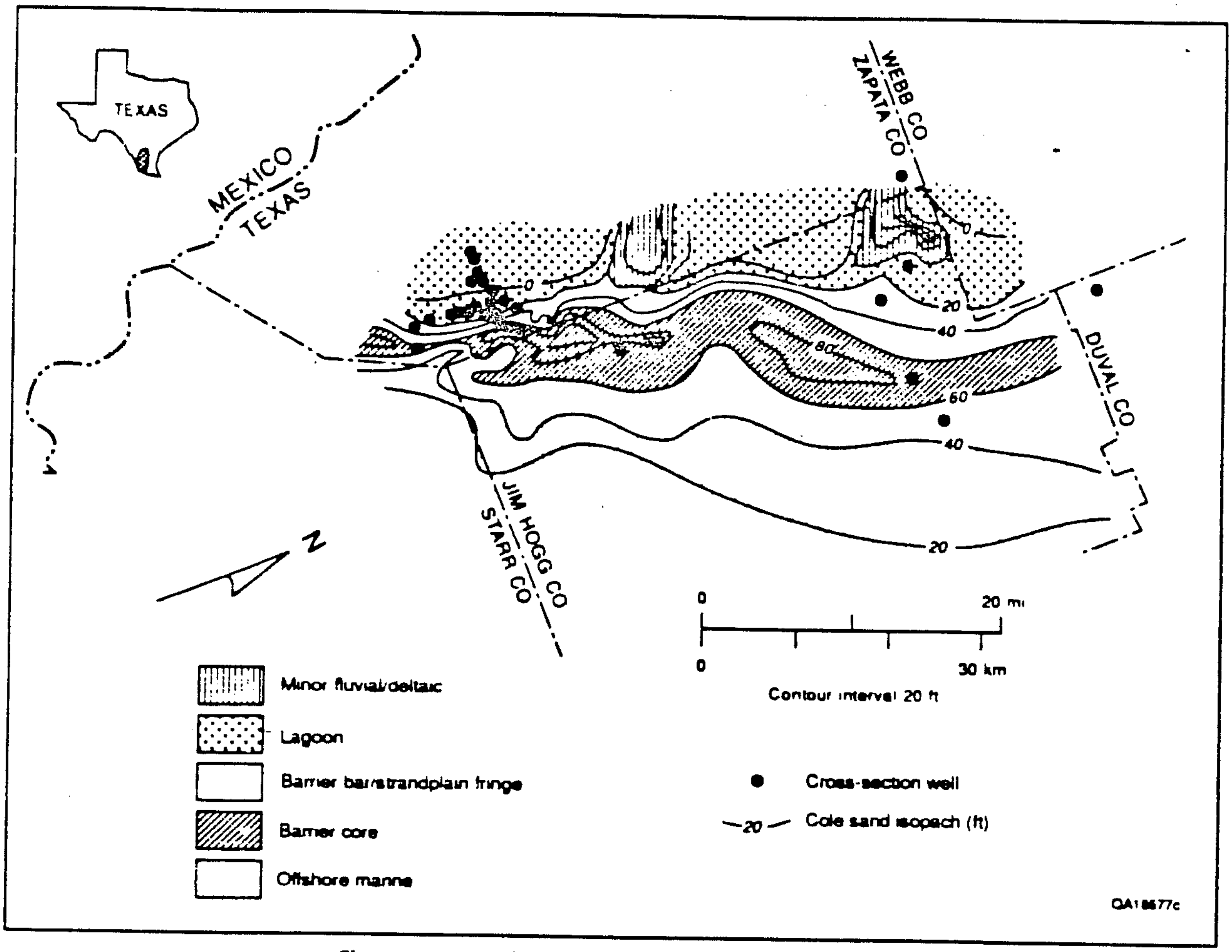


Figure 28. Map of depositional facies of first Cole sand.

Reservoir Texture and Diagenesis

The abundant core allowed sandstone texture and mineralogy to be characterized at Charco Redondo field, which is associated with the updip pinch-out of the first Cole sand (figs. 23 and 29). The oil reservoir at Charco Redondo field is typically a friable, uncemented, clean fine sandstone that coarsens upward as the percentage of fine silt and clay declines (figs. 29 and 30). Fabric has been destroyed by drilling or burrowing organisms. Textural analysis indicates that the reservoir sandstones are poorly to well sorted, strongly fine skewed, and medium to fine grained, and they contain 75 to 95 percent sand and 1 to 7 percent clay. Burrowed, oyster-bearing, fine sandy mudstones overlie and underlie the reservoir. The surrounding mudstones are very poorly sorted and fine skewed, a subequal mixture of fine sand and silt with 15 to 22 percent clay. Thin calcite-cemented zones within the reservoir are tight and apparently affect the distribution of the oil (figs. 29 and 30).

Swelling smectite clays are present in mudstones that encase the reservoir. X-ray diffraction analysis was done to identify clay mineralogy (fig. 31), and reservoir sandstones at Charco Redondo field were found to contain a relatively low percentage (1 to 7 percent) of smectite clays. The presence of smectite clays in other heavy- and medium-oil reservoirs in the Jackson Group is likely to be common owing to the similar depositional and diagenetic history. The percentage of clay minerals in a given reservoir is expected to depend on the location of the reservoir with respect to sand-body pinch-out and to depositional facies.

A detailed cross section based on closely spaced cores (50 ft [15 m]) reveals diagenetic heterogeneities related to the presence of low-permeability zones of calcite-

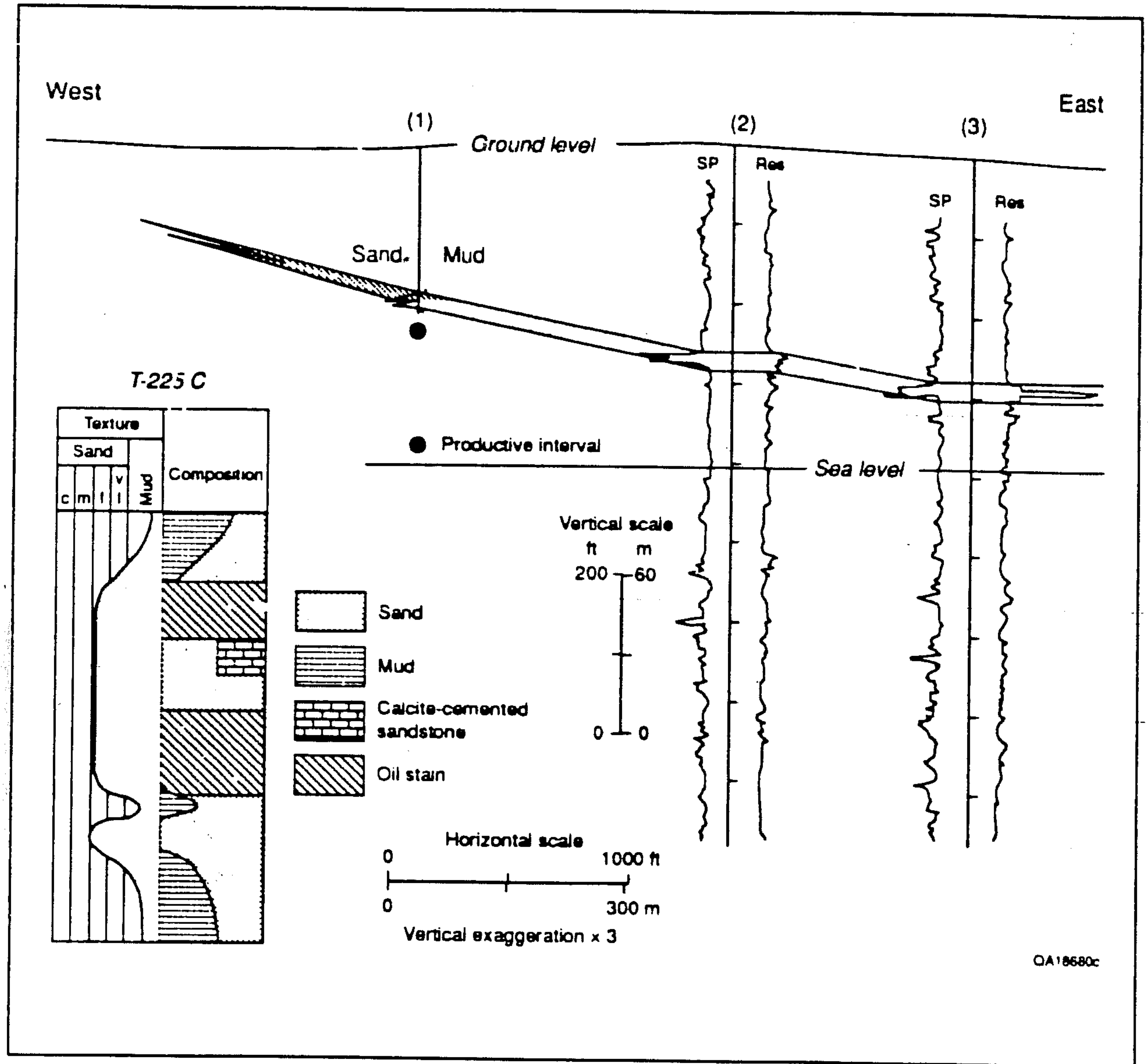


Figure 29. Cross section showing updip pinch-out of first Cole sand at Charco Redondo field. Textural and compositional variations based on description and analysis of core from Charco Redondo field. Well names are listed in appendix 2.

cemented sandstone that apparently segment heavy-oil reservoirs at Charco Redondo field (fig. 32). In an updip position, offlapping calcite-cemented zones occur in the upper part of the sandstone body, dip basinward, and extend to the lower parts of the sandstone body in a downdip position. These zones apparently formed along accretionary-grain surfaces that cross the sand body.

Porosity/permeability plots of reservoirs in the upper Cole sand at Charco Redondo and Seventy-Six West fields reveal a large population characterized by high porosity and permeability and a smaller group characterized by low porosity and permeability (fig. 33). Core analyses indicate zones with high porosity (25 to 35 percent) and permeability (100 to 3,000 md [1.0×10^{-1} to 2.96 μm^2]) are separated by calcite-cemented zones with low porosity (5 to 15 percent) and permeability (0.001 to 10 md [1.0×10^{-6} to 1.0×10^{-2} μm^2]) (fig. 32). The low-permeability, calcite-cemented zones apparently segment the reservoirs into compartments, interrupting reservoir-drainage and potentially affecting pathways of injected geothermal fluids.

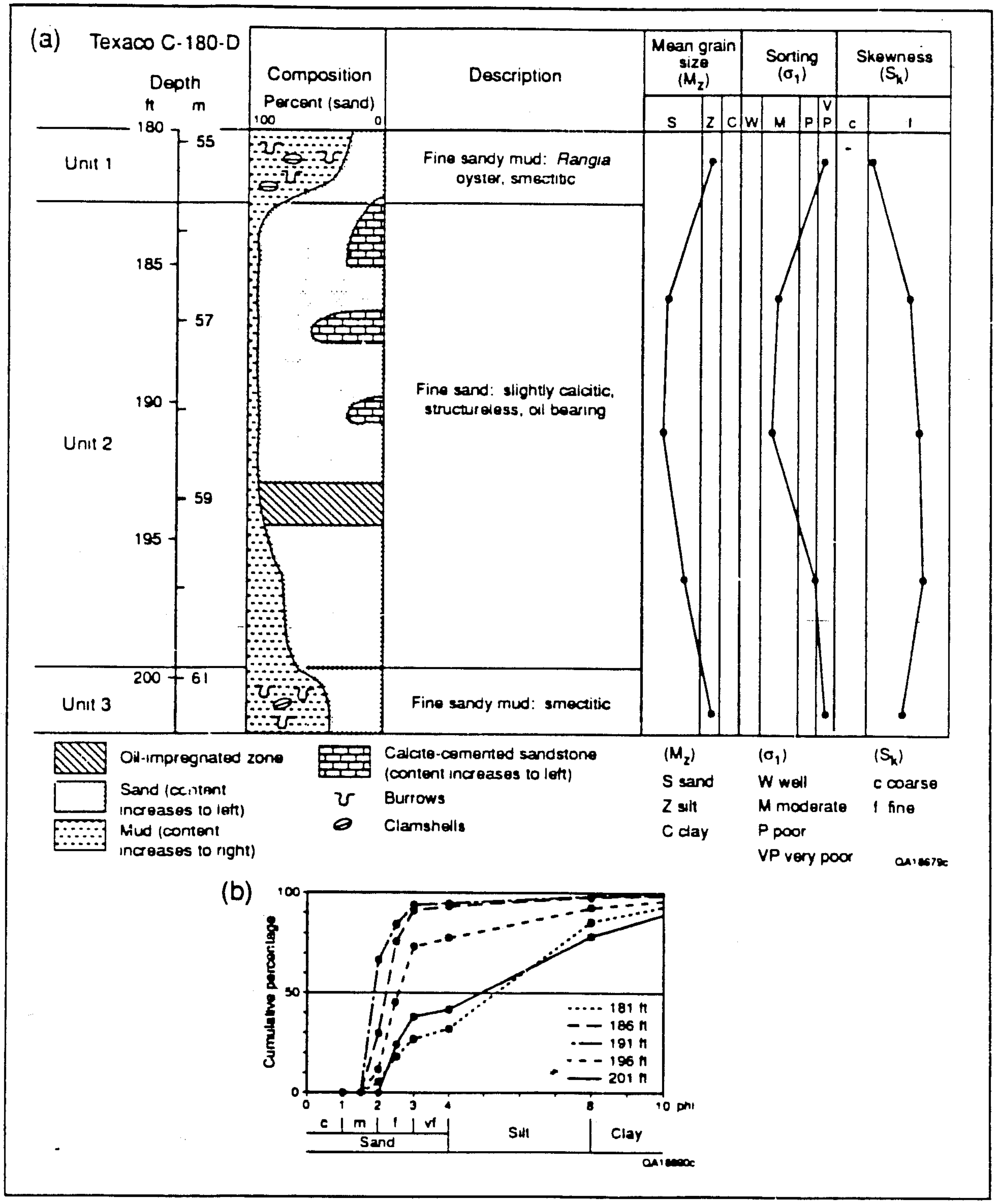


Figure 30. (a) Description of core from upper Jackson Group first Cole sand at Charco Redondo field, Zapata County. (b) Textural data based on wet sieve analysis. Compositional variations result largely from variations in the percentage of matrix clay and silt that is admixed with the abundant fine to medium sand.

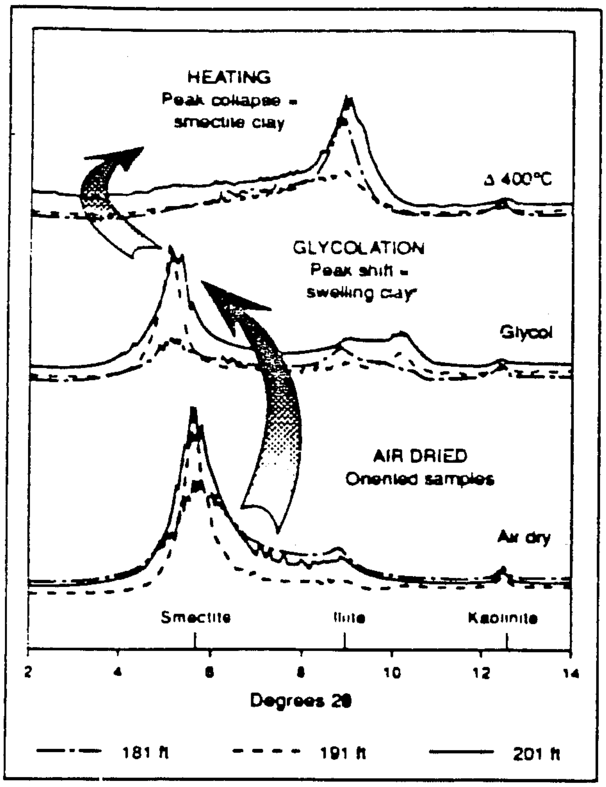


Figure 31. Clay mineral analysis determined by X-ray diffraction of finer than 2 µm separates from first Cole sand from Charco Redondo field, Zapata County. Smectite is the dominant clay mineral in all three samples, illite is present in samples 181 and 201, and kaolinite is present in trace amounts in all three samples. The shift of the smectite peak during glycolation and heating and collapse during heating indicates the presence of swelling clays.

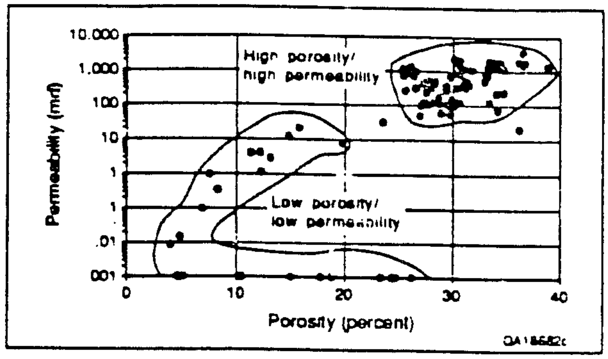


Figure 33. Plot of porosity and permeability from Charco Redondo and Seventy-Six West fields. Most samples are in one of two classes: high porosity (>25%), high permeability (>100 md); and low porosity (<25%), low permeability (<10 md). Samples with low permeability and low porosity are thin calcite-cemented sandstones.

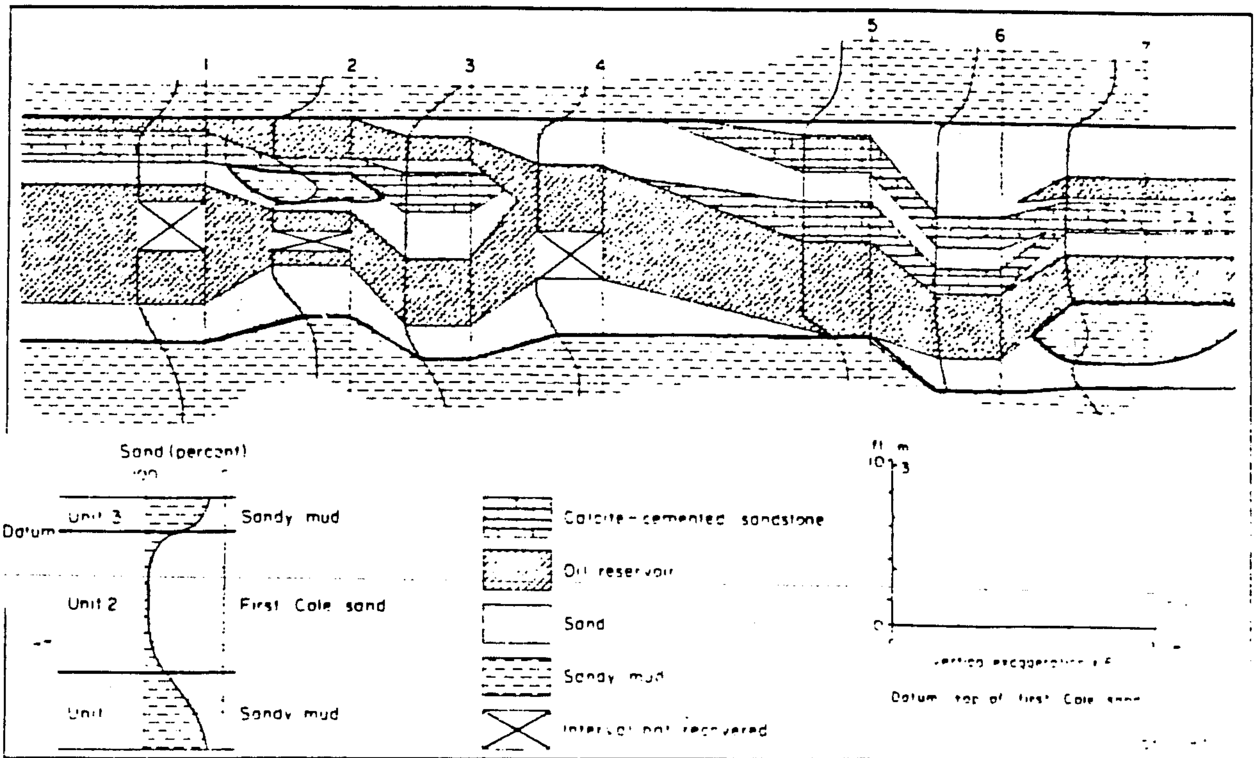


Figure 32. Cross section of Charco Redondo field utilizing core descriptions. Core consisted predominantly of disaggregated sand as a result of shallow depth of burial (180 to 200 ft [55 to 60 m]). Thin calcite-cemented sandstones and muddy intervals appear to be flow barriers that segment the reservoir into compartments. Well names are listed in appendix 2

Suitability of South Texas Heavy-Oil Reservoirs for Thermally Enhanced Oil Recovery

The proximity of heavy-oil reservoirs to geothermal corridors is necessary for geothermal fluids to be used in a geothermally enhanced oil recovery process. However, proximity alone does not automatically ensure the commercial or technical feasibility of the process. Characteristics of the potential target oil and geothermal reservoirs must be carefully considered. Conditions significant for a possible geothermally enhanced oil recovery process in the South Texas area include the (1) size of heavy-oil reservoirs, (2) relatively shallow, thin heavy-oil reservoirs with thin oil columns, (3) generally excellent porosity and a permeability complicated by low-permeability barriers, (4) swelling clays in oil reservoirs, and (5) low permeability in the geothermal reservoir.

Small reservoir size is a major impediment to thermal recovery techniques because the added expense per barrel (m^3) of thermally recovered oil would be high. Heavy-oil reservoirs in the Mirando Trend tend to be small. The 26 heavy-oil reservoirs that overlie the South Texas Wilcox geothermal fairway have a total cumulative production of only 32.9 MMbbl (5.2×10^6 m^3), or an average of 1.3 MMbbl (2.1×10^5 m^3) per reservoir. Of the large reservoirs in Texas, excluding the supergiant Hawkins Woodbine reservoir, the heavy-oil fields have the smallest average size of 28 MMbbl (4.4×10^6 m^3), and medium reservoirs have an average size of 60 MMbbl (9.5×10^6 m^3).

The shallow depths of heavy-oil reservoirs (mean depth of 1,512 ft [461 m]) constrain the upper limit of injection pressures to prevent fracture of the reservoir. However, even at these relatively shallow depths, injected geothermal fluids at 350°F (177°C) will still be hot water and not steam. Although hot water is a less efficient mobilizing agent than steam, such inefficiency would be mitigated if an abundant supply of low-cost geothermal water were available.

A thin, blanket-type oil column in a thin reservoir that pinches out updip is an ideal geometry for favorable sweep efficiencies of conventional (nonthermal) water floods. However, the thinness of the reservoir is unfavorable for hot fluids because heat loss to the surrounding country rock will be high (Martin and others, 1972). Although the lateral continuity of heavy-oil reservoirs is generally favorable for minimizing reservoir compartmentalization, diagenetic calcite-cemented zones have compartmentalized the oil reservoir at Charco Redondo field. Complex lateral facies variations are also likely to segment the oil reservoir. Such zones are thought to be common in other heavy-oil reservoirs of the Mirando Trend. A complete characterization of calcite-cemented zones and facies distribution would help to predict how reservoir performance is affected by flow barriers.

Injection of foreign fluids into an oil reservoir is of concern because of possible reactions that could adversely affect oil production. A common undesirable reaction encountered during injection of fresh water or steam into a reservoir is plugging of pore throats as a result of swelling of smectite clays. Such plugging reduces porosity and permeability. Smectite clays are susceptible to swelling when fresh water becomes bound into the clay structure. High-salinity fluids do not cause smectite clays to swell. Although smectite is present in Mirando Trend reservoirs, the percentage of clay in a given Mirando Trend reservoir is going to be variable and controlled primarily by depositional facies distribution and the relation of oil reservoir to its updip pinch-out.

Inability to predict salinity distribution in the deep upper Wilcox makes the potential problem of swelling clays difficult to assess. The salinity of formation waters is controlled by a complex and poorly understood interaction between local and regional geology, faults, compaction, bulk mineralogy, clay diagenesis, temperature, fluid migration and composition, and salt tectonics (Gregory and others, 1980). Geothermal reservoirs along the Texas Gulf Coast display wide variations in salinity within generalized trends. Salinity typically increases with depth to the geopressured zone. In the geopressured zone salinity decreases. In the deepest zone, salinity trends become unpredictable. Generally, in the South Texas area, the salinity is lower (in the range of <10,000 ppm to >80,000 ppm) than it is at comparable depth along the upper Texas coast, reflecting the general paucity of halite deposits and salt domes (Gregory and others, 1980; Hamlin and others, 1989).

Geothermal fairways in Tertiary strata in the South Texas area, including the Frio, Vicksburg, and upper Wilcox reservoirs, were originally not considered favorable for high-volume production (20,000 bbl/d [0.037 $m^3 s^{-1}$]) of geothermal fluids owing to generally poor reservoir quality (low permeability) compared with that of other geothermal fairways (Bebout and others, 1978; Loucks, 1979; Bebout and others, 1982). However, production rates from South Texas geothermal reservoirs are likely to be as much as 2,000 bbl/d ($\leq$0.004 $m^3 s^{-1}$), which may be adequate for geothermally enhanced oil recovery.

Favorable Colocation Characteristics

A computerized data file at the Railroad Commission of Texas (RRC) was accessed to determine the status of existing wells drilled after 1970 in South Texas that might serve as suitable geothermal wells at a fraction of the cost of drilling a geothermal design well. The wells examined are from the inventory of well logs on file at the Bureau of Economic Geology (BEG). The South Texas well log data base at the BEG exceeds 700 wells, including shallow Jackson logs (100 to 3,000 ft [30 to 914 m]) and deeper Wilcox logs (>8,000 ft [>2,438 m]). BEG has acquired logs from more than 90 percent of the wells in the South Texas area that penetrate through the upper Wilcox. The status of post-1970 wells in the BEG file (266 wells) is as follows: 44 percent (118) are current producers, 23 percent (60) are abandoned producers, 21 percent (55) are plugged and abandoned, 12 percent (33) were not inventoried by the RRC, and pre-1970 wells with logs in the Wilcox interval (294 wells from the BEG well file) have an average depth of 7,238 ft (2,206 m), whereas post-1970 wells have an average depth of 12,836 ft (3,912 m). Of the groups of well types examined, abandoned gas wells were considered most favorable because they are likely to be deep, to have intact casing, and to have an existing infrastructure of pipelines and other production facilities. Abandoned gas-producing wells have the deepest average depth of 14,765 ft (4,500 m). Appendix 4 lists abandoned gas wells in the South Texas five-county area that have a drilled depth below 8,000 ft (2,438 m) and are in the inventory of well logs on file at the BEG.

A 2.5-mi (4-km) radius was plotted around abandoned gas-producing wells in the South Texas colocation area to determine the extent of colocation of the wells and potential heavy- and medium-oil reservoirs (fig. 34). The boundaries of 38 heavy- and medium-oil fields in the Jackson Group contact or lie within a 2.5-mi (4-km) radius around abandoned gas wells in the upper Wilcox in the South Texas colocation area. Approximately 35 abandoned gas wells exist within a 2.5-mi (4-km) radius of a heavy-oil or large reservoir field. Fifty-two percent of the heavy-oil fields in the South Texas area are within 2.5 mi (4 km) of an abandoned well in the deep upper Wilcox, whereas 65 percent of the large (>10 MMbbl [>1.6 × 10^6 m^3]) reservoirs in the Jackson Group (Galloway and others, 1983) are within the same radius. On the basis of surface distance alone, many deep abandoned gas wells are favorably located with respect to heavy- and medium-oil reservoirs.

The productivity of abandoned gas wells (water temperature and water production rates) is not addressed in this report. However, temperatures at a given depth can be estimated in South Texas Wilcox wells on the basis of corrected bottom-hole temperature versus depth (fig. 6) from all wells in the South Texas BEG log file that penetrate the Wilcox. At the average depth of 14,765 ft (4,500 m) for abandoned gas-producing wells in South Texas, the average temperature would be 377°F (192°C).

The conventional production casing size of 5 1/2 inches for the deep upper Wilcox gas wells allows a tubing size of 3 1/2 inches (8.9 cm) or 2 3/8 inches (6.0 cm) to fit inside. With conventional casing and tubing, production rates for geothermal fluids typically are limited to less than 20,000 bbl/d (<0.037 $m^3 s^{-1}$). However, well-productivity limits imposed by standard casing and tubing diameters should not be a significant constraint when the geothermal fluids are to be used for hot-water flooding. During conventional waterflooding in Jackson Group oil reservoirs in South Texas, injection rates are 400 to 600 bbl/d (7.4 × 10^{-4} $m^3 s^{-1}$ to 1.1 × 10^{-3} $m^3 s^{-1}$) for injection wells (RRC hearings files for Seventy-Six West field). A line of five injection wells with an injection rate of 500 bbl/d (9.0 × 10^{-4} $m^3 s^{-1}$) would require a single geothermal well producing 2,500 bbl/d (4.6 × 10^{-3} $m^3 s^{-1}$). Abandoned gas wells could form a cost-effective conduit for accessing geothermal reservoirs because as a group they are relatively deep and can contain relatively hot water.

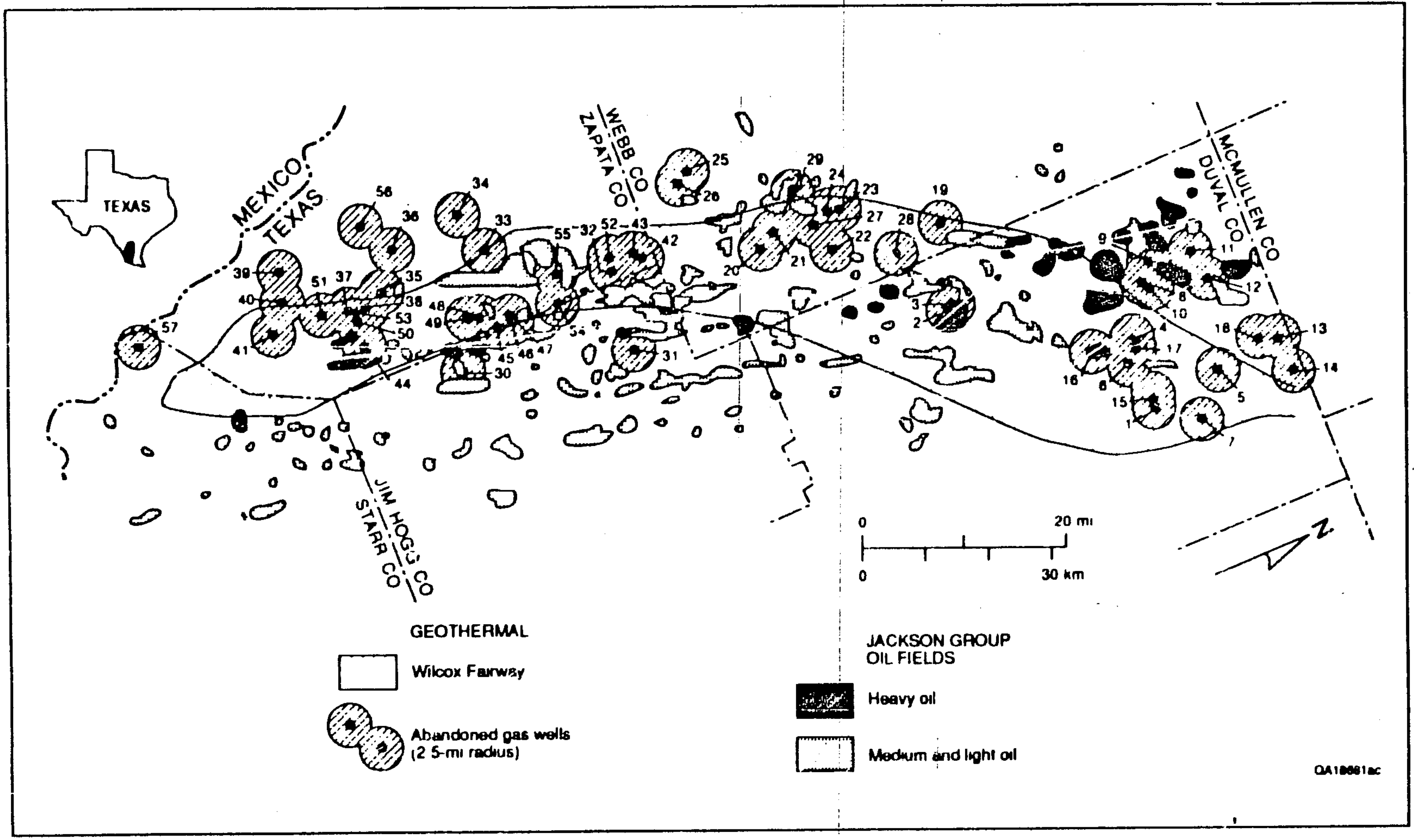


Figure 34. Map showing location of deep abandoned gas wells, oil fields in the upper Jackson, and the South Texas geothermal corridor. A 2.5-mi (4.0-km) radius around the abandoned gas wells intercepts more than half of all heavy-oil reservoirs in the geothermal corridor. Appendix 3 lists the following data for numbered abandoned gas wells: unique BEG identification number, operator/well name, field, and reservoir.

Conclusions

1. The best region in Texas to test the viability of using geopressured-geothermal fluids to improve oil recovery is South Texas, where abundant heavy-oil reservoirs of the Jackson Group immediately overlie geothermal fairways in the upper Wilcox Group. Mirando Trend medium- and heavy-oil reservoirs are well suited for testing TEOR techniques because they have generally excellent porosity and permeability but low recovery efficiency as a result of high oil viscosity. The relatively small size of the heavy-oil reservoirs is a disadvantage.

2. Approximately 35 abandoned gas wells that penetrate the deep, upper Wilcox in the South Texas colocation area are within 2.5 mi (4 km) of reservoirs containing heavy and medium oil in the overlying Jackson Group. With appropriate workover, abandoned gas wells may serve as cost-effective geothermal wells.

3. In the South Texas colocation area, heavy-oil reservoirs are concentrated in the Jackson Group Cole sandstone, whereas medium-oil reservoirs are concentrated in the Government Wells, Loma Novia, and Mirando sandstones. The medium-oil resource is larger than the heavy-oil resource. Microbial degradation and fresh-water washing of light oil are inferred to have concentrated the heavy oil in the shallower Cole sandstone reservoirs.

4. Jackson Group sandstones in South Texas are characterized by a sheetlike geometry as a consequence of deposition in barrier bar/strandplain environments and are surrounded by lagoonal and shelf muds. Heavy- and medium-oil reservoirs in Jackson Group sandstones are trapped predominantly by porosity changes as a result of updip stratigraphic pinch-out of barrier-fringe sands. Subtle structural influences such as nosing and small faults also assist in oil entrapment. Intrafield permeability barriers compartmentalize oil reservoirs in Charco Redondo field

5. Swelling smectite clays occur within Jackson Group reservoir sandstones. When exposed to fresh water, smectite clays will swell and could potentially interfere with reservoir performance by reducing permeability.

6. Deep geothermal fairways in South Texas contain geopressured-geothermal brines having temperatures locally that exceed 350°F (177°C), but they are characterized by low permeability, which would limit their productivities.

7. Upper Wilcox geopressured-geothermal reservoirs in South Texas will not produce brine at the rate of 20,000 bbl/d (0.037 $m^3\ s^{-1}$), which occurred from the Frio Formation at the Pleasant Bayou geothermal test well in Brazoria County. However, production rates of approximately 1,000 to 2,000 bbl/d ($\sim 1.8 \times 10^{-3}\ m^3\ s^{-1}$ to $3.7 \times 10^{-3}\ m^3\ s^{-1}$) have been demonstrated in a production test from the upper Wilcox at Riddle No. 2 Saldana in Zapata County, South Texas. Such rates may be adequate to (1) test the technology for geothermally enhanced oil recovery, (2) determine engineering data on South Texas geothermal reservoirs, and (3) study interactions between geothermal fluids and heavy-oil reservoirs.

Acknowledgments

This work was supported by the U.S. Department of Energy under Cooperative Agreement No. DE-FC07-85NV10412 and managed through the Idaho National Engineering Laboratory Geopressured-Geothermal Program. We thank the following individuals and organizations for their assistance: Mark Miller, Petroleum Engineering Department, The University of Texas at Austin; Ray Fortuna, U.S. Department of Energy, Washington, D.C.; Jane Negus-de Wys, Idaho National Engineering Laboratory; Charles Kimmell, Fanion Production Company; and Shell Exploration and Production Company. We wish to acknowledge two individuals who initially recognized the potential for geothermal energy production—the late Myron Dorfman (who was named the W. A. Moncrief, Jr., Centennial Endowed Chair in Petroleum Engineering at The University of Texas at Austin) and William L. Fisher (current Director of the Bureau of Economic Geology).. Dr. Jane Negus-de Wys has supported, encouraged, and promoted the direct use of geothermal fluids for thermally enhanced oil recovery.

Technical editing was by Tucker F. Hentz. Jay A. Raney, H. Scott Hamlin, Mary L. W. Jackson, W. R. Kaiser, and Paul R. Knox reviewed the manuscript. Michele Bailey, Susan Krepps, Patrice A. Porter, Kerza A. Prewitt, and Tari Weaver drafted the figures under the supervision of Richard L. Dillon, chief cartographer. Others contributing to the publication of this circular were David M. Stephens, text illustration photography; Susan Lloyd, word processing and typesetting; Bobby Duncan, editing; Margaret L. Evans, design; and Kitty Challstrom and Jeannette Miether, proofreading.

References

Ball Associates, Ltd., 1965, Surface and shallow oil-impregnated rocks and shallow oil fields in the United States: U.S. Bureau of Mines Monograph 12, 375 p.

Barker, B. J., Gulati, M. S., Bryan, M. A., and Riedel, K. L., 1991, Geysers reservoir performance: Geo-Heat Center Quarterly Bulletin, v. 13, no. 3, p. 1–14.

Bebout, D. G., Agagu, O. K., and Dorfman, M. H., 1975a, Geothermal resources—Frio Formation, middle Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 75-8, 43 p.

Bebout, D. G., and Bachman, A. L., 1981, eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, 343 p.

Bebout, D. G., Dorfman, M. H., and Agagu, O. K., 1975b, Geothermal resources—Frio Formation, South Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 75-1, 36 p.

Bebout, D. G., and Gutierrez, D. R., 1981, Geopressured geothermal resource in Texas and Louisiana—geological constraints, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 13–28.

Bebout, D. G., Loucks, R. G., Bosch, S. C., and Dorfman, M. H., 1976, Geothermal resources—Frio Formation, upper Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 76-3, 47 p.

Bebout, D. G., Loucks, R. G., and Gregory, A. R., 1978, Frio sandstone reservoirs in the deep subsurface along the Texas Gulf Coast: their potential for production of geopressured geothermal energy: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 91, 93 p.

Bebout, D. G., Weise, B. R., Gregory, A. R., and Edwards, M. B., 1982, Wilcox sandstone reservoirs in the deep subsurface along the Texas Gulf Coast: their potential for production of geopressured geothermal energy: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 117, 125 p.

Blount, C. W., Price, L. C., Wenger, L. M., and Tarullo, M., 1979, Methane solubility in aqueous NaCl solutions at elevated temperatures and pressures: Idaho State University and U.S. Geological Survey, progress report prepared for the U.S. Department of Energy under contract no. ET-78-S-07-1716, 38 p.

Bodner, D. P., Blanchard, P. E., and Sharp, J. M., Jr., 1985, Variations in Gulf Coast heat flow created by groundwater flow: Gulf Coast Association of Geological Societies Transactions, v. 35, p. 19–27.

Bruce, C. H., 1973, Pressured shale and related sediment deformation: mechanism for development of regional contemporaneous faults: American Association of Petroleum Geologists Bulletin, v. 53, no. 1, p. 73–93.

Burger, Jacques, Sourieau, Pierre, and Combarnous, Michael, 1985, Thermal methods of oil recovery: Paris, France, Editions Technip; Gulf Publishing Company, Book Division, 430 p.

Clark, J. D., 1985, Engineering interpretation of exploration drawdown tests, lower Miocene geopressured-brine reservoirs, T-F&S/DOE Gladys McCall No. 1 well, Cameron Parish, Louisiana, *in* Dorfman, M. H., and

Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 23–46.

Craig, F. F., Jr., 1971, The reservoir engineering aspects of water flooding: Society of Petroleum Engineers, Monograph Series, v. 3, 141 p.

Dietz, D. N., 1972, Hot-water drive, *in* Thermal recovery techniques: Richardson, Texas, Society of Petroleum Engineers, Reprint Series, no. 10, p. 79–85.

Dodge, M. M., and Posey, J. S., 1981, Structural cross sections, Tertiary formations, Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology cross sections.

Dorfman, M. H., and Deller, R. W., 1975, eds., Proceedings, First U.S. Gulf Coast Geopressured-Geothermal Energy Conference: The University of Texas at Austin, report prepared for the U.S. Energy Research and Development Administration, 362 p.

_________ 1976, eds., Proceedings, Second U.S. Gulf Coast Geopressured-Geothermal Energy Conference: The University of Texas at Austin, report prepared for the U.S. Energy Research and Development Administration under contract no. E (40-1) 490), 369 p.

Dorfman, M. H., and Fisher, W. L., 1979, eds., Proceedings, Fourth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: The University of Texas at Austin, report prepared for the U.S. Department of Energy, 1692 p.

Dorfman, M. H., and Kehle, R. O., 1974, Potential geothermal resources of Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 77-4, 33 p.

Dorfman, M. H., and Morton, R. A., 1985, eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, 344 p.

DuBar, J. R., 1990, Hot-water flooding: its role in the mobilization of heavy oil, *in* Raney, J. A., project director, Consolidation of geologic studies of geopressured-geothermal resources in Texas: The University of Texas at Austin, Bureau of Economic Geology, open-file report prepared for the U.S. Department of Energy under contract no. DE-FC07-85NV10412, p. 39–61.

Durrett, L. R., 1985, Results of long-term testing of a geopressured-geothermal design well, T-F&S/DOE Gladys McCall No. 1, *in* Dorfman, M. H., and Morton, R. A., 1985, eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 11–22.

Eaton Operating Company, 1991, Contract performance report, October, 1991: Houston, Texas, report prepared for the U.S. Department of Energy under contract no. DE-AC07-85ID12578, 70 p.

Edwards, M. B., 1981, Upper Wilcox Rosita delta system of South Texas: growth-faulted shelf-edge deltas: American Association of Petroleum Geologists Bulletin, v. 65, p. 54–73.

Ewing, T. E., 1983, Jackson-Yegua barrier/strandplain sandstone, *in* Galloway, W. E., Ewing, T. E., Garrett, C. M., Tyler, Noel, and Bebout, D. G., Atlas of major Texas oil reservoirs: The University of Texas at Austin, Bureau of Economic Geology Special Publication, p. 30–32.

_________ 1986, Structural styles of the Wilcox and Frio growth-fault trends in Texas: constraints on geopressured reservoirs: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 154, 86 p.

Fertl, W. H., Chilingarian, G. V., and Rieke, H. H., III, 1976, Abnormal formation pressures: New York, Elsevier, 382 p.

Fisher, W. L., Proctor, C. V., Jr., Galloway, W. E., and Nagle, J. S., 1970, Depositional systems in the Jackson Group of Texas—their relationship to oil, gas, and uranium: Gulf Coast Association of Geological Societies Transactions, v. 20, p. 234–261.

Galloway, W. E., Ewing, T. E., Garrett, C. M., Tyler, Noel, and Bebout, D. G., 1983, Atlas of major Texas oil reservoirs: The University of Texas at Austin, Bureau of Economic Geology Special Publication, 139 p.

Garg, S. K., and Riney, T. D., 1985, Analysis of flow data from the DOW/DOE L. R. Sweezy No. 1 Well, *in* Dorfman, M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 71–80.

Gould, T. L., Kenner, C. B., and Clark, J. D., 1981, *in* Bebout, D. G., and Bachman, A. L., 1981, eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 317–324.

Gregory, A. R., Dodge, M. M., Posey, J. S., and Morton, R. A., 1980, Volume and accessibility of entrained (solution) methane in deep geopressured reservoirs—Tertiary formations of the Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology, open-file report prepared for the U.S. Department of Energy under contract no DE-AC08-78ET11397, 390 p.

Hamlin, H. S., Walter, T. G., and Kreitler, C. W., 1989, Colocation of heavy oil and geopressured-geothermal brine resources: examples from South Texas and Kern County, California, *in* Kreitler, C. W., project director, Consolidation of geologic studies of geopressured-geothermal resources in Texas: The University of Texas at Austin, Bureau of Economic Geology, open-file report prepared for the U.S. Department of Energy under contract no. DE-FC07-85NV10412, p. 187–241.

Hannah, J. L., 1975, The potential of low temperature geothermal resources in northern California: California Department of Conservation, Division of Oil and Gas, Geothermal Unit, 53 p.

Hopf, R. W., 1986, Cole field re-entered, Duval and Webb Counties, Texas, *in* Stapp, W. L., ed., Contributions to the geology of South Texas: San Antonio, South Texas Geological Society, p. 83–99.

Hughes, E. E., and Campbell, R. G., 1985, Hybrid power system for Pleasant Bayou geopressured well, *in* Dorfman,

M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 251–257.

Hyatt, D. B., 1990, Geology and production characteristics of the Seventy-Six West field, Duval County, Texas: Gulf Coast Association of Geological Societies Transactions, v. 40, p. 305–318.

Interstate Oil Compact Commission, 1984, Major tar sand and heavy oil deposits of the United States: Oklahoma City, Oklahoma, 272 p.

Jones, P. H., 1976, Natural gas resources of the geopressured zones in the northern Gulf of Mexico basin, *in* Natural gas from unconventional geologic sources: National Research Council, Board of Mineral Resources, Commission on Natural Resources, National Academy of Sciences, p. 17–33.

Kaiser, W. R., Ayers, W. B., Jr., and La Brie, L. W., 1980, Lignite resources in Texas: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 104, 52 p.

Kaiser, W. R., Johnston, J. E., and Bach, W. N., 1978, Sand-body geometry and the occurrence of lignite in the Eocene of Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 78-4, 19 p.

Kehle, R. O., 1971, Geothermal survey of North America, 1971 annual progress report: Research Committee, American Association of Petroleum Geologists (unpublished), 31 p.

King, R. L., and Lee, W. J., 1976, An engineering study of the Hawkins (Woodbine) field: Journal of Petroleum Technology, v. 28, p. 123–128.

Klauzinski, R. Z., 1981, Testing of six "Wells of Opportunity" during 1980 and 1981, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 171–176.

Lane, E. C., and Garton, E. L., 1925, "Base" of a crude oil: U.S. Bureau of Mines, Report of Investigations 3279, 12 p.

Lewis, C. R., and Rose, S. C., 1970, A theory relating high temperatures to overpressures: Journal of Petroleum Technology, v. 22, p. 11–16.

Lombard, D. B., 1985, Geopressured geothermal brines—a resource for the future, *in* Dorfman, M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 3–7.

Loucks, R. G., 1979, Sandstone distribution and potential for geopressured geothermal energy production in the Vicksburg Formation along the Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 79-4, 33 p.

Loucks, R. G., Dodge, M. M., and Galloway, W. E., 1980, Importance of secondary leached porosity in lower Tertiary sandstone reservoirs along the Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 80-2, 8 p.

Loucks, R. G., Richman, D. L., and Milliken, K. L., 1981, Factors controlling reservoir quality in Tertiary sandstones and their significance to geopressured geothermal production: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 111, 41 p.

Lunis, B. C., 1990, Geopressured-geothermal direct use potentials are significant: Geo-Heat Center Quarterly Bulletin, v. 12, no. 2, p. 1–7.

Lunis, B. C., Negus-de Wys, Jane, Plum, M. M., Lienau, P. J., Spencer, F. J., and Nitschke, G. F., 1991, The feasibility of applying geopressured-geothermal resources to direct uses: EG&G Idaho, Idaho National Engineering Laboratory, EGG-EP-9839, 58 p.

Martin, W. L., Dew, J. N., Powers, M. L., and Steves, H. B., 1972, Results of a Tertiary hot waterflood in a thin sand reservoir, *in* Thermal recovery techniques: Richardson, Texas, Society of Petroleum Engineers, Reprint Series, no. 10, p. 97–110.

McCulloh, R. P., and Piño, M. A., 1981, Geopressured geothermal resource potential of Miocene Bayou Hebert Prospect, Vermilion and Iberia Parishes, Louisiana, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 237–240.

Meriwether, John, ed., 1977, Proceedings, Third U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Lafayette, Louisiana, The University of Southwestern Louisiana, report prepared for the U.S. Department of Energy under contract no. EG-77-G-05-5557, variously paginated.

Milliken, K. L., Land, L. S., and Loucks, R. G., 1981, History of burial diagenesis determined from isotopic geochemistry, Frio Formation, Brazoria County, Texas: American Association of Petroleum Geologists Bulletin, v. 65, no. 8, p. 1397–1413.

Morton, R. A., 1981, Pleasant Bayou No. 2—A review of rationale, ongoing research and preliminary test results, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 55–58.

Morton, R. A., Ewing, T. E., and Tyler, Noel, 1983, Continuity and internal properties of Gulf Coast sandstones and their implications for geopressured fluid production: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 132, 70 p.

Negus-de Wys, Jane, 1990, eds., Proceedings, Industrial Consortium for the Utilization of the Geopressured-Geothermal Resource: EG&G, Inc., Idaho National Engineering Laboratory, Idaho Falls, Idaho, 2 vols.

__________ 1991, ed., Proceedings, Industrial Consortium for the Utilization of the Geopressured-Geothermal Resource: EG&G, Inc., Idaho National Engineering Laboratory, Idaho Falls, Idaho, 2 vols.

Negus-de Wys, Jane, Kimmell, C. E., Hart, G. F., and Plum, M. M., 1991, The feasibility of recovering medium to heavy oil using geopressured-geothermal fluids: EG&G Idaho, Idaho National Engineering Laboratory, EGG-EP-9840, 107 p.

North, F. K., 1985, Petroleum geology: Unwin Hyman, Winchester, Massachusetts, 631 p.

Peterson, K. P., 1981, Structural geology of "Wells of Opportunity" tested during 1980 and 1981, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 163–170.

Philippi, G. T., 1977, On the depth, time, and mechanism of origin of the heavy- to medium-gravity naphthenic crude oils: Geochimica et Cosmochimica Acta, v. 41, no. 1, p. 33–52.

Podio, A. L., Gray, K. E., Isokrari, O. F., Knapp, R. M., Silberberg, I. H., and Thompson, T. W., 1976, Reservoir research and technology, *in* Reservoir research and technology, Proceedings, Second Geopressured-Geothermal Energy Conference, The University of Texas at Austin, Center for Energy Studies, v. 3, part 1, p. 54–56.

Prats, Michael, 1986, Thermal recovery: Richardson, Texas Society of Petroleum Engineers, 283 p.

Pritchett, J. W., and Riney, T. D., 1985, Analysis of the T-F&S/DOE Gladys McCall No. 1 Well test results and history matching simulations for sand zone no. 8, *in* Dorfman, M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 47–56.

Riggs, S. R., Ellison, S. P., Jr., Fisher, W. L., Galloway, W. E., Jackson, M. L. W., and Morton, R. A., 1991, Mineral resources and geopressured-geothermal energy, *in* Salvador, A., ed., The Gulf of Mexico Basin: Geological Society of America, The geology of North America, v. J, chapter 16, p. 495–527.

Rodgers, J. S., Coble, Larry, and Hamilton, J. R., 1985, Analyses of DOW/DOE No. 1 L. R. Sweezy well tests, *in* Dorfman, M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 57–70.

Rodgers, R. W., and Durham, C. O., Jr., 1985, The Sweet Lake geopressured-geothermal project, Cameron Parish, Louisiana—final summary and analysis, *in* Dorfman, M. H., and Morton, R. A., eds., Proceedings, Sixth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: New York, Pergamon Press, p. 93–103.

Schultz, A. L., 1986, Geology of the first Mirando Sand, North Lopez Unit, Lopez field, Webb and Duval Counties, Texas, *in* Stapp, W. L., ed., Contributions to the geology of South Texas: San Antonio, South Texas Geological Society, p. 100–108.

Seni, S. J., and Walter, T. G., 1990, Colocation of geothermal and heavy-oil reservoirs: a South Texas update, *in* Raney, J. A., project director, Consolidation of geologic studies of geopressured-geothermal resources in Texas: The University of Texas at Austin, Bureau of Economic Geology, open-file report prepared for the U.S. Department of Energy under contract no. DE-FC07-85NV10412, p. 1–37.

Smith, H. M., 1968, Crude oil: qualitative and quantitative aspects—the petroleum world: U.S. Bureau of Mines Bulletin 642, 125 p.

Snyder, F. C., and Pilger, R. H., Jr., 1981, Structural-stratigraphic setting of Lafourche Crossing prospect, Louisiana, *in* Bebout, D. G., and Bachman, A. L., 1981, eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 233–236.

Swanson, R. K., Oetking, P., Osoba, J. S., and Hagens, R. C., 1976, Development of an assessment methodology for geopressured zones of the Upper Gulf Coast based on a study of abnormally pressured gas fields in South Texas: San Antonio, Southwest Research Institute, report prepared for the U.S. Energy Research and Development Administration under contract no. E (11-1) 2687, 75 p.

Tissot, B. P., and Welte, D. H., 1984, Petroleum formation and occurrence: New York, Springer-Verlag, 699 p.

Tyler, Noel, Galloway, W. E., Garrett, C. M., Jr., and Ewing, T. E., 1984, Oil accumulation, production characteristics, and targets for additional recovery in major oil reservoirs of Texas: The University of Texas at Austin, Bureau of Economic Geology Geological Circular 84-2, 31 p.

Tyler, Noel, Holtz, M. H., Garrett, C. M., Jr., and White, W. G., 1991, Atlas of major Texas oil reservoirs: data base: The University of Texas at Austin, Bureau of Economic Geology computerized data base.

Wallace, R. H., Kraemer, T. F., Taylor, R. E., and Wesselman, J. B., 1979, Assessment of geopressured-geothermal resources in the northern Gulf of Mexico basin, *in* Muffler, L. J. P., ed., Assessment of geothermal resources in the United States—1978: U.S. Geological Survey Circular 790, p. 132–155.

West, T. S., 1963, Typical stratigraphic traps, Jackson trend of South Texas: Gulf Coast Association of Geological Societies Transactions, v. 13, p. 67–78.

Winker, C. D., Morton, R. A., Ewing, T. E., and Garcia, D. D., 1983, Depositional setting, structural style, and sandstone distribution in three geopressured geothermal areas, Texas Gulf Coast: The University of Texas at Austin, Bureau of Economic Geology Report of Investigations No. 134, 60 p.

Woodruff, C. M., 1982, Geothermal resources of Texas: The University of Texas at Austin, Bureau of Economic Geology Energy and Mineral Resources Maps, scale 1:1,000,000.

Wrighton, Fred, 1981, An economic overview of geopressured solution gas, *in* Bebout, D. G., and Bachman, A. L., eds., Proceedings, Fifth U.S. Gulf Coast Geopressured-Geothermal Energy Conference: Baton Rouge, Louisiana State University, p. 45–48.

Appendix 1: Medium- and Heavy-Oil Reservoirs

Figure 15

Jackson-Yegua Barrier/Strandplain

1. Lundell
2. Seven Sisters
3. Aviators
4. Govt. Wells N
5. Govt. Wells S
6. Mirando City
7. Lopez
8. Piedre Lumbre
9. Escobas
10. Hoffman

Cap Rock

11. Humble Cap Rock
12. Sour Lake Cap Rock
13. Spindletop Cap Rock

Piercement Salt Dome

14. Big Creek
15. Port Neches
16. Damon Mound
17. Clam Lake
18. Barbers Hill
19. Fannett
20. Markham

Woodbine Fluvial/Deltaic/Strandplain

21. Hawkins

Paluxy Fault Line

22. Pewitt Ranch
23. Sulphur Bluff
24. Talco

Figure 18

Heavy-oil fields (reservoirs)

1. Alworth (Cole sand)
2. Bruni S
3. Bruja Vieja (Cole sand)
4. Cedro Hill
5. Charco Redondo
6. Colmena
7. Dinn
8. Edlasater W (Cole 950)
9. El Puerto N (O'Hern)
10. Govt. Wells N (900 sand)
11. Govt. Wells N (1000 sand)
12. Govt. Wells N (1150)
13. Govt. Wells N (1550)
14. Govt. Wells S (1900)
15. Hoffman E
16. Joe Moss (500 sand)
17. Kohler NE (Mirando No. 2)
18. Las Animas–Lefevre
19. Lopez N (Lopez)
20. Lundell
21. Orlee
22. Peters N (first Cole sand)
23. Rancho Solo
24. Rancho Solo (second Cole sand)
25. Rancho Solo (extension)
26. Richardson

Large oil fields

A. Aviators
B. Colorado
C. Conoco Driscoll
D. Escobas
E. Govt. Wells N
F. Govt. Wells S
G. Hoffman
H. Loma Novia
I. Lopez
J. Lundell
K. Mirando City
L. O'Hern
M. Piedre Lumbre
N. Prado
O. Seven Sisters

Appendix 2: Wells on Cross Sections

Figure 21 (A–A')

1.	ZA-406	Southland Royalty No. 2 A. Garcia
2.	DU-126	Royal Oil and Gas No. 1-R F. Lowe Bindewald

Figure 23 (B–B')

1.	ZA-364	Delaney Oil and Gas No. 3 A. de Vela
2.	ZA-394	Moss No. 1 Vela
3.	ZA-359	Moss No. 3 Vela
4.	ZA-357	Florence E. Green No. 1 Mission Prod.
5.	ZA-349	Moss and Watson No. 6 Vela
6.	ZA-418	Suburban Propane No. 1 Trevino
7.	ZA-338	DeLange and Fallis No. 2 P. Trevino
8.	ZA-334	Schwab et al. No. 1-B A. Garcia
9.	ZA-410	Guardian No. 1 A. Garcia
10.	ZA-406	Southland Royalty No. 2 A. Garcia
11.	ZA-413	Allen No. 1 A. Garcia

Figure 24 (A–A')

1.	ZA-406	Southland Royalty No. 2 A. Garcia
2.	JH-37	Humble Oil and Refining No. 1 Colorado GU 1
3.	JH-34	Cox and Cox No. 1 A. Martinez
4.	DU-78	Union Producing Co. No. 1 Brennan-Benavides
5.	DU-89	Getty (Texaco) No. 1 V. K. Gruy
6.	DU-59	Flournoy et al. No. 1 Cuellar Brothers
7.	DU-146	Shell Oil No. 2 A. R. Hubbard GU 1
8.	DU-126	Royal Oil and Gas No. 1-R F. Lowe Bindewald

Figure 28 (C–C')

1.	JH-1	Shell Oil No. 1 J. E. Fulbright
2.	JH-3	Austral No. 2 Marrs McLean
3.	JH-15	Atlantic Richfield No. C-4 Marrs McLean Trust
4.	JH-34	Cox and Cox No. 1 A. Martinez
5.	JH-334	Coastal Well Service No. 1 Felix Stroman
6.	JH-324	Humble Oil and Refining No. 2 Moody Ranch
7.	JH-326	Humble Oil and Refining No. 1-D Mostena Oil and Gas

Figure 29

1.	T-225-C	Texaco No. T-225-C Charco Redondo
2.	ZA-330	Schwab et al. No. 3 Flores
3.	ZA-310	Miller and Pierce No. 1 E. J. Flores et al.

Figure 32

1.	T-180-D	Texaco No. T-180-D Charco Redondo
2.	T-180-C	Texaco No. T-180-C Charco Redondo
3.	T-180-B	Texaco No. T-180-B Charco Redondo
4.	T-180-A	Texaco No. T-180-A Charco Redondo
5.	T-O-A	Texaco No. T-O-A Charco Redondo
6.	T-O-B	Texaco No. T-O-B Charco Redondo
7	T-O-C	Texaco No. T-O-C Charco Redondo

Appendix 3. Abandoned Deep Gas Wells in South Texas

Well number	BEG number	Well name	Field name	Reservoir
1	DU-50	Harkins No. 1-A Garza-Cuellar	Los Reyes	Weatherby sand
2	DU-65	Eason-Harper No. 1-160 Peters Estate	Peters S	Wilcox
3	DU-66	Eason No. 1 Peters Estate	Peters S	Wilcox
4	DU-81	K. P. Exploration No. 2 Wm. Hubberd	Leedy	Wilcox B
5	DU-82	Exxon No. 1 Bravo Land Co.	Rejeletta S	10,000 sand
6	DU-83	Harkins and Co. No. 1 La Venada	La Venada	Weatherby
7	DU-85	Shell No. 1 J. F. Welder Heirs	Bold Forbes	Carrizo P
8	DU-96	Marine Contractors et al. No. 1 Hall-Weiderkehr	Govt. Wells	Mirando
9	DU-97	Fair and Woodward No. 1 J. Luptack	East 76	Wilcox
10	DU-99	Harkins and Co. No. 1-100 D.C.R.C.	Govt. Wells	
11	DU-105	Harkins and McDonald No. 2 D.C.R.C.	Piedre Lumbre	Wilcox W
12	DU-110	Exxon No. 2-H D.C.R.C.	Petrox	Wilcox 7100
13	DU-124	Inland Ocean No. 1 Ross	Labbe S	Wilcox Upper
14	DU-126	Royal Oil and Gas No. 1-R F. Lowe Bindewald	Hostetter S	Wilcox 10,200
15	DU-132	Harkins and Co. No. 1 A. S. Serna	Los Reyes	Weatherby sand
16	DU-141	Shell No. 1 J. S. Garcia	Rosita NW	Wilcox S 8
17	DU-153	Tana Oil No. 1 Hahl		
18	DU-158	T. D. Exploration No. 1 De la Fuente	Herbst-Wilcox	Herbst III
19	WE-2	Houston Oil and Minerals No. 1 F. Billings	Lopez W	Floyd-A
20	WE-16	Hughes and Hughes No. A-1 O. Laurel	Tom Sherman	10500
21	WE-49	E. P. Operating Co. No. 2 A. Z. Laurel	El Milagro	Seventh Hinnant
22	WE-52	Forest Oil No. 1 Rosa V. de Benavides	Cole W	Wilcox
23	WE-56	Conoco No. 1 Carlos Benavides	Picoso	Wilcox 10,300
24	WE-58	Conoco No. B-3 Carlos Benavides	Picoso	Wilcox 11,800
25	WE-59	Conoco No. A-2 Alicia Henry-BMT	Perdido	Taylor Lobo
26	WE-60	Conoco No. A-1 Alicia Henry-BMT	Perdido	Taylor Lobo
27	WE-65	Sagex No. 1 C. B. Dickenson	Picoso E	Carrizo 8000
28	WE-67	Aminoil USA No. 2 Moglia	Moglia	11200
29	WE-68	Forest Oil No. 1 G. C. Villareal GU	Oilton N	10600
30	JH-25	Pan American Sales Corp. No. 3 Gutierrez	Travis Ward	First Hinnant
31	JH-34	Cox and Cox No. 1 A. Martinez	Petroleo	Wilcox
32	ZA-17	Blocker No. 252 Hinnant	Toquachie Creek	
33	ZA-41	Pennzoil Production No. 1 A. R. Gutierrez	Jennings S	Wilcox 8550
34	ZA-46	Houston Oil and Minerals No. 1 Asche	Charco	9100
35	ZA-60	Pennzoil Production No. 1 A. Vela	Comitas SW	7000
36	ZA-63	Samedan Oil No. 1 Maties Unit	Cinco de Mayo	10150
37	ZA-82	Pennzoil Production No. 1 C-1 A. Vela	El Grullo	6760
38	ZA-85	Pennzoil Production No. 1 P. Gonzales Vela	El Grullo	7300
39	ZA-88	Texas Oil and Gas Corp. No. 1 Guerra "M"	Roleta	6800, 7483
40	ZA-92	Gulf Energy and Minerals U.S. No. 1-A G. Gonzalez	Falcon Lake N	Wilcox 6400
41	ZA-100	Good Hope Refineries No. 1 Falcon	Onepol	Wilcox Upper
42	ZA-130	Hughes and Hughes No. G-1 L. A. Hinnant	Aviators S	11800

Appendix 3 (cont.)

Well number	BEG number	Well name	Field name	Reservoir
43	ZA-132	Hughes and Hughes No. M-1 Hinnant	Aviators S	Wilcox 11050
44	ZA-140	Shell Oil No. 1 L. Taylor	El Grullo E	Taylor sand
45	ZA-146	Shell Oil No. 1 G. G. Hinojosa	Fandango	
46	ZA-150	Shell Western E and P No. A-2 H. B. Zachry	Fandango	Wilcox Upper T6
47	ZA-151	Shell Oil No. 3 Muzza	Fandango	Wilcox Upper T6
48	ZA-153	Shell Oil No. 2 L. Garza et al.	Fandango	
49	ZA-156	Shell Oil No. 3 M. T. Longoria	Randado Ranch	Queen City
50	ZA-160	Killam and Hurd No. 2 E. Vela	Wildcat	
51	ZA-170	Pennzoil Production No. 1 A. Garcia	Volpe SE	Wilcox 7730
52	ZA-181	Blocker Explor. No. 1-112 L. A. Hinnant	Toquachie Creek	Wilcox
53	ZA-184	Entex Petroleum No. 1 A. M. Vela	Herlinda Vela	Wilcox
54	ZA-185	Gulf Oil No. 1 Saldana Unit	Martinez	First Hinnant Upper
55	ZA-190	Canus Petroleum No. 1 San Miguel et al.	Cuellar	9215
56	ZA-199	Gulf Oil No. 1 Vela de Peña	Cinco de Mayo	8500
57	ST-12	Corder No. 2 N. Silva	Falcon Dam	Wilcox